U.S. DEPARTMENT OF COMMERCE
National Technical Information Service

PB-276 681

PRELIMINARY ENVIRONMENTAL ASSESSMENT OF COMBUSTION MODIFICATION TECHNIQUES: VOLUME II. TECHNICAL RESULTS

ACUREX CORP., MOUNTAIN VIEW, CALIF.

PREPARED FOR
INDUSTRIAL ENVIRONMENTAL RESEARCH LAB.
RESEARCH TRIANGLE PARK, N.C.

OCT 77

PB 276 681

EPA U.S. Environmental Protection Agency
Office of Research and Development

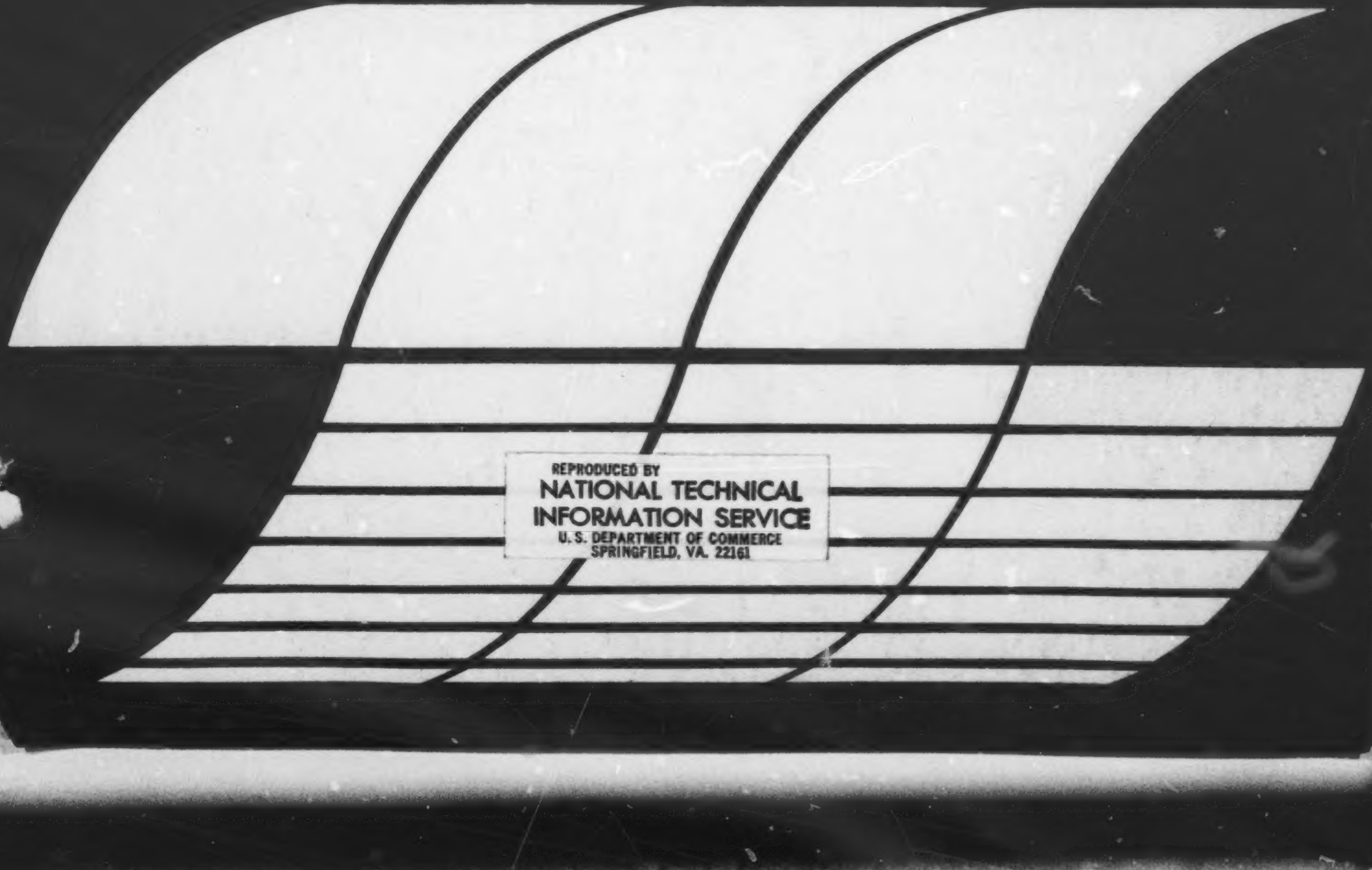
Industrial Environmental Research
Laboratory
Research Triangle Park, North Carolina 27711

EPA-600/7-77-119b
October 1977

PRELIMINARY ENVIRONMENTAL ASSESSMENT OF COMBUSTION MODIFICATION TECHNIQUES:

Volume II. Technical Results

Interagency
Energy-Environment
Research and Development
Program Report



REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into seven series. These seven broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The seven series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally--compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

REVIEW NOTICE

This report has been reviewed by the participating Federal Agencies, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Government, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

TECHNICAL REPORT DATA

(Please read Instructions on the reverse before completing)

1. REPORT NO.
EPA-600/7-77-119b

2.

3. RECIPIENT'S ACCESSION NO.
PB276681

4. TITLE AND SUBTITLE
Preliminary Environmental Assessment of Combustion Modification Techniques: Volume II. Technical Results

5. REPORT DATE
October 1977

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)
H. B. Mason, A. B. Shimizu, J. E. Ferrell, G. G. Poe, L. R. Waterland, and R. M. Evans

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
Acurex Corporation, Aerotherm Division
485 Clyde Avenue
Mountain View, California 94042

10. PROGRAM ELEMENT NO.
EHE624A

11. CONTRACT/GRANT NO.
68-02-2160

12. SPONSORING AGENCY NAME AND ADDRESS
EPA, Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED
Special; 6/76-2/77

14. SPONSORING AGENCY CODE
EPA/600/13

15. SUPPLEMENTARY NOTES
IERL-RTP project officer for this report is Joshua S. Bowen, Mail Drop 65, 919/541-2470.

16. ABSTRACT
The report gives preliminary methodologies, data compilation, and program priorities for assessing stationary combustion sources and NOx combustion modification technologies. Equipment characterizations and multimedia emission inventories are presented for utility and industrial boilers, commercial and residential warm air furnaces, gas turbines, IC engines, industrial processes, and advanced combustion processes. Control costs and operational, energy, and environmental impacts are compiled and discussed for current and emerging combustion modification NOx controls. Incremental emissions of CO, HC, and particulate due to NOx controls can be minimized through control development engineering. Other effluents (POMs, segregating trace metals, and sulfates) show potential for increased emissions with some combustion modifications. Significant data gaps in emissions and impacts of multimedia pollutants, with and without NOx controls, are noted. Program priorities for field tests and process studies to augment the data base are presented.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Air Pollution	Internal Combustion Engines	Air Pollution Control	13B	
Combustion		Stationary Sources	21B	21G
Combustion Control	Operating Costs	Combustion Modification		14A
Nitrogen Oxides	Coal, Fuel Oil	Emission Factors	07B	
Dust	Natural Gas	Control Costs	11G	
Boilers	Organic Compounds	Environmental Assessment	13A	07C
Gas Turbines	Inorganic Compounds		13G	

18. DISTRIBUTION STATEMENT
Unlimited

19. SECURITY CLASS *(This Report)*
Unclassified

20. SECURITY CLASS *(This page)*
Unclassified

NO OF PAGES
581

22. PRICE
A25-A01

EPA Form 2220-1 (9-73)

EPA-600/7-77-119b
October 1977

PRELIMINARY ENVIRONMENTAL ASSESSMENT OF COMBUSTION MODIFICATION TECHNIQUES:

Volume II. Technical Results

by

H.B. Mason, A.B. Shimizu, J.E. Ferrell,
G.G. Poe, L.R. Waterland, and R.M. Evans

Acurex Corporation
Aerotherm Division
485 Clyde Avenue
Mountain View, California 94042

Contract No. 68-02-2160
Program Element No. EHE624A

EPA Project Officer: Joshua S. Bowen

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, N.C. 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, D.C. 20460

ABSTRACT

The report gives preliminary methodologies , data compilation, and program priorities for assessing stationary combustion sources and NOx combustion modification technologies. Equipment characterizations and multimedia emission inventories are presented for utility and industrial boilers, commercial and residential warm air furnaces, gas turbines, IC engines, industrial processes, and advanced combustion processes. Control costs and operational, energy, and environmental impacts are compiled and discussed for current and emerging combustion modification NOx controls. Incremental emissions of CO, HC, and particulate due to NOx controls can be minimized through control developement engineering. Other effleunts (POMs, segregating trace metals, and sulfates) show potential for increased emissions with some combustion modifications. Significant data gaps in emissions and impacts of multimedia pollutants, with and without NOx controls, are noted. Program priorities for field tests and process studies to augment the data base are presented.

FOREWORD

This report documents results generated during the first 6 months of EPA Contract 68-02-2160: "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies." The EPA Project Officer is J. S. Bowen and the Deputy Project Officer is R. E. Hall of the Combustion Research Branch, IERL/RTP. This report was prepared by Aerotherm Division of Acurex Corporation. Principal Contributors were:

- Preface and Section 1: Introduction — H. B. Mason
- Section 2: NO_x Source Characterization — A. B. Shimizu and K. Salvesen
- Section 3: Pollutant Characterization — J. E. Ferrell and G. R. Offen (Aerotherm); H. M. Utidijian and P. Atkins (Equitable Environmental Health); G. Lauer, A. Lloyd and R. MacGregor (Environmental Research and Technology)
- Section 4: NO_x Control Characterization — G. G. Poe, A. Balakrishnan, C. Castaldini, Z. Chiba
- Section 5: Multimedia Emission Inventory of NO_x Sources — A. B. Shimizu, K. Salvesen and K. Wolfe
- Section 6: Evaluation of Incremental Emissions due to NO_x Controls — L. Waterland, C. Castaldini, G. G. Poe
- Section 7: Environmental Assessment Priorities — R. M. Evans, L. Waterland, G. R. Offen, H. B. Mason
- Appendices — K. Wolfe, M. McDonald, D. Rafinejad

The Program Manager is W. H. Nurick. H. B. Mason is the Project Engineer. C. B. Moyer provided technical review.

The contributions of the following individuals and organizations are gratefully acknowledged: J. S. Bowen, R. E. Hall, D. G. Lachapelle, W. S. Lanier, G. B. Martin and J. Wasser of the Combustion Research Branch, IERL; R. Vosper of the Coen Company; S. Greenfield, L. Attaway and L. Husting of

Greenfield, Attaway and Tyler Company; D. W. Pershing and J. O. L. Wendt of the University of Arizona; D. P. Teixeira and R. M. Perhac of the Electric Power Research Institute; and A. Eschenroeder and G. Hidy of Environmental Research and Technology.

PREFACE

This is the first in a series of 11 special reports to be documented in the "Environmental Assessment of Stationary Source NO_x Combustion Modification Technologies" (NO_x E/A). This preface describes the organization, approach, and expected results of the NO_x E/A and relates this initial report to the total program. The Introduction section reviews the background and needs addressed by the program and by this report.

The NO_x E/A is a 36-month program which began in July 1976. The program has two main objectives: (1) to identify the multimedia environmental impact of stationary combustion sources and NO_x combustion modification controls; and (2) to identify the most cost-effective, environmentally-sound NO_x combustion modification controls for attainment and maintenance of current and projected NO_2 air quality standards to the year 2000.

By achieving these objectives, the NO_x E/A program will show the economic, environmental and operational impact of reducing NO_x to a given level on specific combustion sources with current and emerging control technology. This information is addressed to the following groups:

- Equipment manufacturers and users concerned with selecting the most appropriate control techniques to meet regulatory standards
- Control R&D groups concerned with providing a sufficient breadth of environmentally-sound control techniques to meet the diverse control implementation needs in NO_2-critical Air Quality Control Regions
- Environmental planners involved in formulating abatement strategies to meet current or projected air quality standards

NO_x E/A Scope and Approach

The scope and approach of the NO_x E/A come largely from its place in the broad program of assessments of energy systems and industrial processes which is being administered by EPA's Office of Research and Development. This assessment program involves a series of coordinated efforts to evaluate the environmental impact and control potential of multimedia effluents — air, land and water — from current and emerging energy and industrial processes. The results of these efforts will define pollution control development needs and priorities, identify economic and environmental trade-offs among competitive processes, and will ultimately guide regulatory policy. This broad assessment program is organized in a hierarchy, in which each assessment draws on the results of the preceding study. The six major types of assessments now planned are listed below together with specific assessment programs relevant to the NO_x E/A:

- Emissions Assessment: quantify multimedia emissions from effluent streams of specific processes
  - Emissions Assessment of Conventional Combustion Systems (TRW)
- Source Assessment: determine environmental impact of multimedia emissions from source effluent streams and rank sources according to impact
  - Source Assessment (Monsanto Research Corporation)
- Process Environmental Assessment: determine multimedia environmental impact of effluent streams for a specific process; evaluate pollution control requirements; identify control R&D needs
  - Fluidized Bed Combustion E/A (Battelle)
  - Residual Oil Utilization E/A (Catalytic)
- Industry Environmental Assessment: conduct industry-wide aggregate process E/A; rank control development needs for the industry; identify environmental trade-offs of alternate processes
- Pollutant Control Environmental Assessment: conduct multi-industry process E/A of all sources of a given pollutant; identify most cost-effective, environmentally acceptable control systems; identify R&D requirements to meet national emissions standards or local air quality goals
  - NO_x Control E/A (Aerotherm)
- Integrated Technology Assessment: evaluate environmental, technological and socioeconomic trade-offs for emerging energy systems or processes for use in deciding regulatory strategy; integrate results of process, industry and pollutant control E/A's
  - Integrated Technology Assessment of Electric Utility Energy Systems (Teknekron)
  - Integrated Assessment of Coal-Based Energy Technology (Planned)

The goal of these assessment activities is to synthesize data and technology from related programs, and to develop a standardized basis of comparison of the results of the various efforts. In support of this goal, EPA's Industrial Environmental Research Laboratories (RTP and Cincinnati) have established steering committees to coordinate the assessment programs. This coordination will make it possible for the NO_x E/A to utilize results from the emissions assessments, source assessments, and environmental assessments previously listed, and to provide inputs to the integrated technology assessments.

The NO_x E/A, as part of the overall pollutant control E/A activity, will assess the following combination of process parameters and environmental impacts:

- Fuel combustion stationary NO_x sources: utility, industrial, commercial and residential boilers; commercial and residential warm air furnaces; IC engines; gas turbines; industrial process combustion; advanced energy systems; and minor sources. Other sources (mobile and noncombustion) will be considered only to the extent that they are needed to determine the NO_x contribution from stationary combustion sources.
- Conventional and alternate gaseous, liquid and solid fuels
- Combustion modification NO_x controls with potential for implementation to the year 2000; other controls (tail gas cleaning, mobile controls) will be considered only to estimate the future need for combustion modifications
- Source effluent streams potentially affected by NO_x controls
- Nonstandard operating conditions during which the emissions may be affected by NO_x controls
- Primary and secondary gaseous, liquid and solid pollutants potentially affected by NO_x controls
- Pollutant impacts on human health and terrestrial or aquatic ecology

In order to achieve the overall objectives of this NO_x E/A program (described on the first page of this preface), strong emphasis will be placed throughout the program on screening and setting priorities among the combinations of process parameters and potential impacts. This approach infers that the major effort will be focused on the sources, controls, and potential impacts which are likely to be significant in the national NO_x abatement strategy. It also infers that effort in the early stages of the program will concentrate on near-term source/control needs, while emphasis will be switched later to longer range control needs to the year 2000. The comprehensive ranking of the process and impact combinations which is the principal outcome of the program will not be able to be made until most of the tasks in the program are complete. Throughout the effort, however, priorities will be screened on the basis of the most recent findings, which will be periodically updated and reevaluated as new data become available.

For simplicity, the screening and ranking of alternatives are being conducted in two steps. In the first step, potential source/fuel/control combinations are being screened on the basis of significant application in this century. This requires projecting the use of specific source/fuel combinations as well as estimating which control systems will be needed to meet current or anticipated NO_2-related air quality standards. This in turn will entail process studies of specific source/control combinations and air quality modeling of NO_2-sensitive areas which examine NO_x abatement strategies.

The second step in screening and ranking alternatives is to prioritize effluent streams/operating modes/pollutant combinations on the basis of incremental multimedia impact due to the use of NO_x controls. This ranking will be done for the significant source/fuel/control combinations which result from the first step screening. In addition, this second step involves compiling emissions data for specific effluent streams and operating modes, as well as compiling impact criteria for specific pollutants. Iteration between the results of the two steps is necessary to ensure that the incremental impact of NO_x controls identified in the second step is considered in estimating control needs in the first step.

NO_x E/A Program Structure

As shown schematically in Figure P-1, the NO_x E/A program is structured to incorporate the above approach. The two major tasks are: Environmental Assessment and Process Engineering (Task B5); and Systems Analysis (Task C). Each of these tasks is designed to achieve one of the overall objectives of the NO_x E/A program cited earlier. In Task B5, the environmental, economic, and operational impacts of specific source/control combinations will be assessed. On the basis of this assessment, the incremental multimedia impacts from the use of combustion modification NO_x controls will be identified and ranked. Task C will in turn use the results of Task B5 to identify and rank the most effective source/control combinations to comply, on a local basis, with the current NO_2 air quality standards and projected NO_2-related standards.

As shown in Figure P-1, the key tasks supporting Tasks B5 and C are Baseline Emissions Characterization (Task B1), Evaluation of Emission Impacts and Standards (Task B2), and Emission Data (Task B3). The arrows in Figure P-1 show the sequence of subtasks and the major interactions among

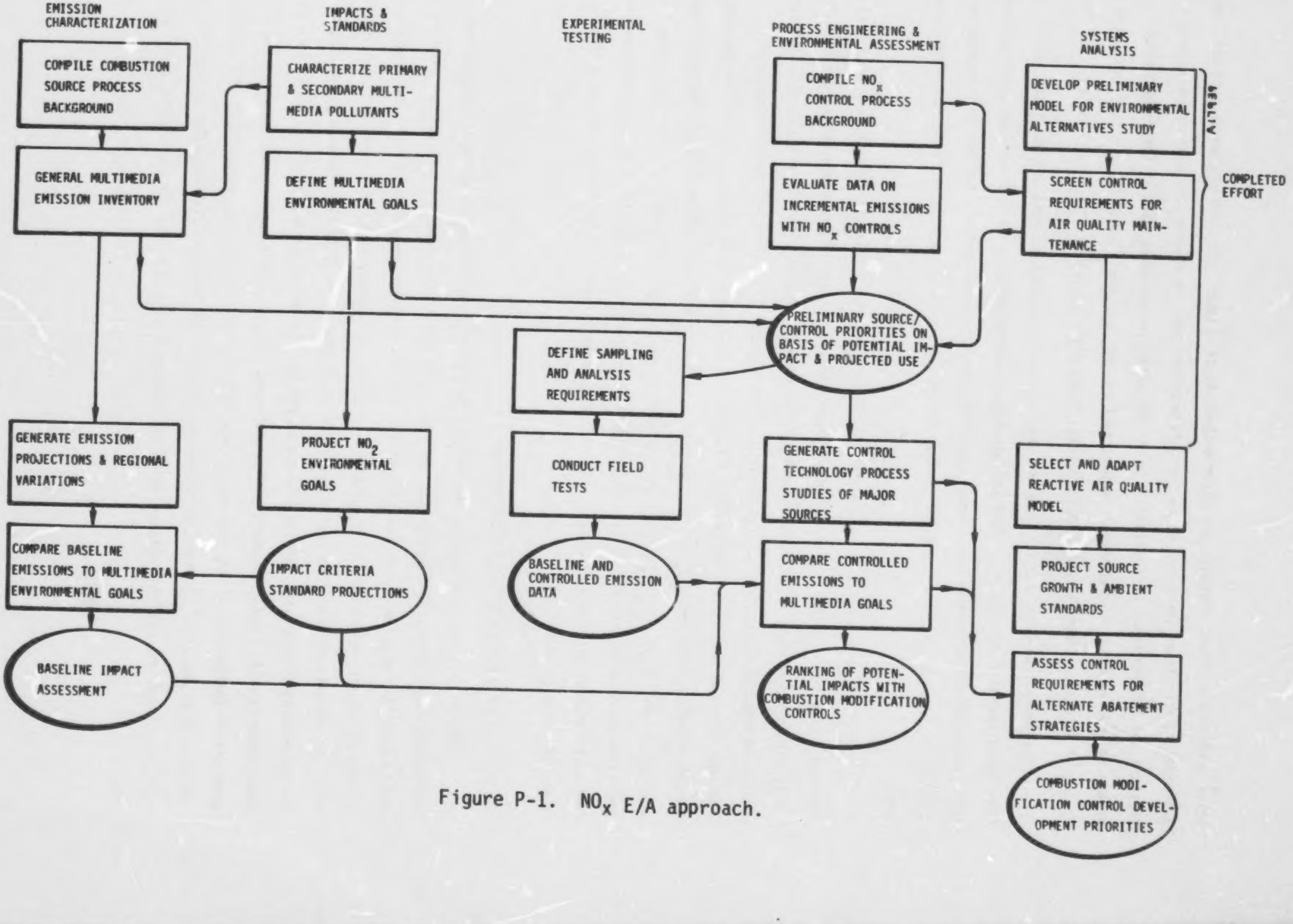

EMISSION CHARACTERIZATION
IMPACTS & STANDARDS
EXPERIMENTAL TESTING
PROCESS ENGINEERING & ENVIRONMENTAL ASSESSMENT
SYSTEMS ANALYSIS
COMPILE COMBUSTION SOURCE PROCESS BACKGROUND
CHARACTERIZE PRIMARY & SECONDARY MULTI-MEDIA POLLUTANTS
COMPILE NO$_x$ CONTROL PROCESS BACKGROUND
DEVELOP PRELIMINARY MODEL FOR ENVIRONMENTAL ALTERNATIVES STUDY
A17939
GENERAL MULTIMEDIA EMISSION INVENTORY
DEFINE MULTIMEDIA ENVIRONMENTAL GOALS
EVALUATE DATA ON INCREMENTAL EMISSIONS WITH NO$_x$ CONTROLS
SCREEN CONTROL REQUIREMENTS FOR AIR QUALITY MAIN-TENANCE
COMPLETED EFFORT
PRELIMINARY SOURCE/CONTROL PRIORITIES ON BASIS OF POTENTIAL IM-PACT & PROJECTED USE
DEFINE SAMPLING AND ANALYSIS REQUIREMENTS
GENERATE EMISSION PROJECTIONS & REGIONAL VARIATIONS
PROJECT NO$_2$ ENVIRONMENTAL GOALS
CONDUCT FIELD TESTS
GENERATE CONTROL TECHNOLOGY PROCESS STUDIES OF MAJOR SOURCES
SELECT AND ADAPT REACTIVE AIR QUALITY MODEL
COMPARE BASELINE EMISSIONS TO MULTIMEDIA ENVIRONMENTAL GOALS
IMPACT CRITERIA STANDARD PROJECTIONS
BASELINE AND CONTROLLED EMISSION DATA
COMPARE CONTROLLED EMISSIONS TO MULTIMEDIA GOALS
PROJECT SOURCE GROWTH & AMBIENT STANDARDS
BASELINE IMPACT ASSESSMENT
RANKING OF POTEN-TIAL IMPACTS WITH COMBUSTION MODIFICATION CONTROLS
ASSESS CONTROL REQUIREMENTS FOR ALTERNATE ABATEMENT STRATEGIES
COMBUSTION MODI-FICATION CONTROL DEVEL-OPMENT PRIORITIES

Figure P-1. NO$_x$ E/A approach.

tasks. The oval symbols identify the major outputs of each task. The subtasks under each main task are shown on the figure from the top to the bottom of the page in roughly the same order in which they will be carried out. More detail is given for tasks on the upper half of the figure which relate to this report. An additional support task of this program — Identification and Characterization of Alternate Clean Fuels for Area Sources (Task B4) — has been omitted for clarity.

The initial work on this NO_x program began by compiling process data and multimedia emissions data for stationary NO_x sources. Both uncontrolled baseline emission data as well as data for sources using NO_x controls were compiled. Process and emission data based on test results from related programs will continue to be incorporated as they become available throughout the duration of the program.

These data were used to initiate the following preliminary characterizations and data evaluations: stationary source equipment and effluent streams, as well as baseline multimedia emissions (B1); multimedia primary and secondary pollutants and impacts (B2); stationary source NO_x controls and incremental emissions due to control (B5). These characterizations and data evaluations, together with the preliminary screening of future source/control requirements (C), are documented in this report. This information will serve as a data base for the subsequent comprehensive process studies, as well as for refining emission inventories and impact criteria. It will also guide decisions on requirements for subsequent field test programs and on setting priorities for process and environmental assessment studies. The activities which remain to be carried out in each of the tasks are summarized below.

Task B1 — Baseline Emission Characterization

Task B1 focuses on assessing the multimedia pollution potential of effluent streams from uncontrolled stationary fuel combustion sources. This involves a generalized (nonsite-specific) analysis of the emission rates specified in the earlier emission inventory, as well as an analysis of how pollutants emitted are transformed and transported. After these emission rates are updated with Task B3 test results, the resulting estimates of ground level concentration will be compared to the estimates of maximum permissible concentrations (on an impact basis) generated in Task B2. This comparison will indicate which effluent streams and pollutants pose potential environmental problems in the absence of NO_x controls. This information will serve as a baseline reference for the more comprehensive assessment of incremental impacts of NO_x controls conducted in Task B5, and will also highlight effluent streams which may require control systems for pollutants other than NO_x.

The efforts carried out in Task B1 (emission inventory, projection of source/fuel usage, and specification of geographical variations in source/fuel use) will support the final pollution potential assessment. The results of this task will also show the potential effect on pollution of growth trends for specific source/fuel combinations and the proximity of specific sources to population centers. These data will also support the air quality modeling of alternate NO_x controls in Task C, where local (AQCR) inventories and source projections to the year 2000 are needed to determine the NO_x controls required to meet air quality standards.

Task B2 — Emission Impacts and Standards

The goal of Task B2 is to generate a set of pollutant/impact criteria data which can be used to assess the environmental soundness of effluent streams and NO_x control systems in Tasks B1 and B5. The scope of the task includes gaseous, liquid, and solid effluents that have a potential impact on human health through inhalation or ingestion via the food chain, or that affect aquatic or terrestrial flora or fauna. The result will be a pollutant/impact matrix of conservative estimates of permissible ambient concentrations.

During the preliminary characterization of emissions and evaluation of data carried out so far, emphasis has been placed on gaseous stream pollutants which affect human health through inhalation. One reason for this is that the vast majority of combustion-generated pollutants which may be impacted by combustion modification NO_x controls is present in gaseous effluent streams. Another reason is that it is easier to identify and quantify the impact of inhaled gaseous pollutants on human health than other kinds of pollutants or receptors. In addition, the effect of inhaled pollutants is more readily generalized without regard to site-specific impact factors such as regional flora or fauna and regional food chain vectors. The site-specific impact criteria are not neglected, however. They are generalized somewhat in B2 by considering the most sensitive receptor for each pollutant regardless of location. This "worst case" screening approach will in turn be modified in the individual assessments of B5, where the impacts for specific source/control combinations will be evaluated for two or more representative ecosystems. Task B5 will also examine other potential impacts of NO_x controls, such as noise or thermal pollution and impact on material systems.

In addition to the efforts described above, Task B2 will also evaluate and project air quality standards for NO_2 and related pollutants. These projected standards will be used in Task C, where alternate air quality standards will serve as the criteria for defining future NO_x control needs and, hence, the scope of this program. Projected standards to be evaluated include:

- Change in level of the current annual arithmetric average standard on the basis of human health effects
- Short-term NO_2 standard on the basis of human health effects or the role of NO_x in the formation of photochemical smog
- Standards for secondary pollutants from NO_x, such as acid nitrates and nitrosamines

The purpose of these evaluations will not be to suggest standards, but rather to anticipate their impact, if and when promulgated, on control implementation needs.

Task B3 — Emission Data

Task B3 will rely heavily on data from emissions and control development test programs now being carried out. Where necessary, this data base will be augmented by test programs conducted as part of this program. Test requirements will be defined from the preliminary emission characterizations and data evaluations documented in this report. The test approach will follow the Level I and Level II guidelines for sampling, chemical analysis and bioassays now being established by the IERL steering committees on environmental assessments. Although some uncontrolled baseline tests will be conducted, most tests will be on field equipment with extensive NO_x control and on prototype systems using advanced NO_x control techniques.

Task B5 — Environmental Assessment

The relationship of Tasks B5 and C to the other tasks in the program has been described above. Following this report, the effort in Task B5 will generate process data and environmental assessments for specific source/control combinations. These studies will be done in order of descending priority. Initially, the sources and controls involved in current and planned NO_x control implementation programs will be investigated. The results of these investigations will be used to assess the environmental soundness of best available control technology. Once this has been completed, minor or emerging sources and advanced controls projected for far-term application will be considered. The results of this effort will help to identify specific environmental problems which should be considered in the control development program and/or future control implementation strategies.

Task C — Systems Analysis

Task C differs from other tasks in this program in that it is confined to NO_x and secondary pollutants from NO_x (e.g., oxidants). Since the other tasks are aimed at quantifying environmental impact, they must deal not only with NO_x and secondary pollutants from NO_x, but with all other pollutants potentially affected by NO_x controls. Air quality modeling of these other pollutants would, ideally, be beneficial in the environmental impact assessment, but beyond the scope of this program (and generally beyond the state of the art). The air quality modeling in Task C, therefore, focuses on the impact of alternate NO_x controls on ambient concentrations of NO_2 and secondary pollutants from NO_x. The impact on other pollutants is factored into the air quality model externally during the final ranking of control systems.

The Systems Analysis effort will be conducted in two stages. The first stage, preliminary screening, will focus solely on controls requirements to maintain the current NO_2 annual average air quality standard. For this stage, a crude, nonreactive, modified rollback model will be used to scope the most cost-effective combustion modification controls for a number of possible mobile source control and source growth scenarios. Two Air Quality Control Regions (AQCRs), encompassing a broad range of equipment/fuel types and stationary/mobile emissions, will be modeled.

The second stage of the Systems Analysis will use a reactive dispersion air quality model to assess short-term standards and standards based on secondary pollutants from NO_x. In this stage, three additional AQCRs will be considered. Gridded inventories and growth projections for specific AQCRs will be compiled for the more complex air quality model.

The results of the efforts discussed here will be documented in a series of reports as follows:

- First Annual Report: July 1977
- Emission and Pollution Potential Characterizations of Stationary Combustion NO_x Sources (B1): September 1977
- Process Engineering and Environmental Assessment of NO_x Controls for Utility Boilers: January 1978
- Process Engineering and Environmental Assessment of NO_x Controls for Industrial Boilers (B5): May 1978
- Process Engineering and Environmental Assessment of NO_x Controls for Gas Turbines (B5): September 1978
- Process Engineering and Environmental Assessment of NO_x Controls for Residential and Commercial Heating Systems (B5): November 1978
- Second Annual Report: July 1978
- Assessment of Alternate Clean Fuels Use in Area Sources (B4): September 1978

- Process Engineering and Environmental Assessment of NO_x Controls for IC Engines (B5): December 1978
- Process Engineering and Environmental Assessment of NO_x Controls for Industrial Process Furnaces (B5): March 1979
- Process Engineering and Environmental Assessment of NO_x Controls for Advanced Combustion Systems (B5): May 1979
- Final Report: July 1979

TABLE OF CONTENTS

Section Page

1 INTRODUCTION . . . 1-1

1.1 Basis for Current Control Technology Requirements . . . 1-1
1.2 Anticipated Control Technology Requirements . . . 1-3

1.2.1 Attainment of NAAQS . . . 1-3
1.2.2 Maintenance of NAAQS . . . 1-4
1.2.3 Attainment and Maintenance of Additional NO$_2$ Standards . . . 1-5

1.3 Requirements for NO$_x$ Control Technology Development . . . 1-6
1.4 Purpose of the NO$_x$ E/A . . . 1-7
1.5 Purpose of This Report . . . 1-7

2 NO$_x$ SOURCE CHARACTERIZATION . . . 2-1

2.1 Stationary Fuel Combustion Sources . . . 2-4

2.1.1 Utility and Large Industrial Boilers >73 MW (>250 MBtu/hr) Heat Input . . . 2-4
2.1.2 Packaged Boilers . . . 2-15
2.1.3 Warm Air Furnaces and Other Commercial and Residential Combustion Equipment . . . 2-20
2.1.4 Gas Turbines . . . 2-30
2.1.5 Stationary Reciprocating IC Engines . . . 2-39
2.1.6 Industrial Process Heating . . . 2-41
2.1.7 Advanced Combustion Processes . . . 2-47
2.1.8 Incineration . . . 2-53

2.2 Mobile Combustion Sources . . . 2-53
2.3 Noncombustion Sources . . . 2-54
2.4 Fugitive Emissions . . . 2-55
2.5 Conclusions and Summary . . . 2-56

2.5.1 Data Evaluation . . . 2-56
2.5.2 Tabulation of Stationary Fuel Combustion Equipment Categories . . . 2-57

3 POLLUTANT CHARACTERIZATION . . . 3-1

3.1 Pollutant Identification and Transformation . . . 3-2
3.2 Pollutant Effects Research Methodology . . . 3-14

3.2.1 Methods to Assess Ambient Pollutant Health Effects . . . 3-14
3.2.2 Methods of Assessing Pollutant Impacts on Biota . . . 3-23

3.3 Concentration Estimates for Screening Combustion Related Pollutants . . . 3-29
3.4 Summary and Conclusions . . . 3-54

4 NO$_x$ CONTROL CHARACTERIZATION . . . 4-1

4.1 Survey of NO$_x$ Control Regulations . . . 4-2
4.2 Combustion Process Modifications . . . 4-9

4.2.1 General Concepts on NO$_x$ Formation and Control . . . 4-9
4.2.2 Low Excess Air Firing . . . 4-22
4.2.3 Flue Gas Recirculation . . . 4-27
4.2.4 Off-Stoichiometric Combustion . . . 4-32
4.2.5 Load Reduction . . . 4-37
4.2.6 Burner Modifications . . . 4-42
4.2.7 Water Injection . . . 4-48
4.2.8 Reduced Air Preheat . . . 4-51
4.2.9 Ammonia Injection . . . 4-54
4.2.10 Costs of Combustion Process Modifications . . . 4-57

TABLE OF CONTENTS (Continued)

4.3 Fuel Denitrification 4-74

4.3.1 Oil Denitrification 4-74
4.3.2 Coal Denitrification 4-79

4.4 Fuel Additives 4-81
4.5 Alternate and Mixed Fuels 4-84

4.5.1 Western Coals 4-84
4.5.2 Low-Btu Gas 4-85
4.5.3 Medium- and High-Btu Synthetic Gas 4-85
4.5.4 Synthetic Oil from Coal 4-86
4.5.5 Coal-Oil Slurry 4-86
4.5.6 Methanol 4-86
4.5.7 Water-Oil Emulsions 4-87

4.6 Alternate Concepts 4-87

4.6.1 Catalytic Combustion 4-88
4.6.2 Fluidized Bed Combustion 4-89
4.6.3 Repowering 4-90
4.6.4 Combined Cycles 4-90
4.6.5 High Temperature Gas Turbines 4-91

4.7 Flue Gas Treatment 4-92

4.7.1 Dry FGT Processes 4-95
4.7.2 Wet FGT Processes 4-95

4.8 Evaluation and Summary 4-96

5 MULTIMEDIA EMISSION INVENTORY OF NO_x SOURCES 5-1

5.1 Fuels: Properties and Consumption 5-2

5.1.1 Fuel Properties 5-2
5.1.2 Fuel Consumption 5-4

5.2 Emission Factors 5-15

5.2.1 Utility and Large Industrial Boilers 5-17
5.2.2 Packaged Boilers 5-19
5.2.3 Warm Air Furnaces 5-22
5.2.4 Gas Turbines 5-24
5.2.5 Reciprocating IC Engines 5-24
5.2.6 Industrial Process Combustion 5-24

5.3 Effect of Emission Control Regulations 5-27

5.3.1 Particulate Control 5-29
5.3.2 SO_x Control 5-31
5.3.3 NO_x Control 5-31

5.4 Emissions Inventory 5-32

5.4.1 Stationary Source Sector Emissions 5-33
5.4.2 Controlled NO_x Emissions 5-33

5.5 Summary and Conclusions 5-42

5.5.1 Summary of NO_x Emissions from all Sources 5-42
5.5.2 Summary of Air Pollutant Emissions 5-45
5.5.3 Comparison with Data 5-45
5.5.4 Conclusion 5-57

TABLE OF CONTENTS (Continued)

6 EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS 6-1

6.1 Preliminary Screening 6-2

6.1.1 Boilers 6-3
6.1.2 Reciprocating IC Engines and Gas Turbines 6-12
6.1.3 Warm Air Furnaces 6-15

6.2 Emissions Data Evaluation 6-20

6.2.1 Carbon Monoxide 6-20
6.2.2 Hydrocarbon Emissions 6-33
6.2.3 Particulate Emissions 6-41
6.2.4 Trace Metals 6-54
6.2.5 Sulfates 6-60
6.2.6 Organics 6-69
6.2.7 Nitrates 6-74

6.3 Evaluation and Summary 6-76

7 ENVIRONMENTAL ASSESSMENT PRIORITIES 7-1

7.1 Evaluation of NO_x Control Requirements 7-3

7.1.1 Preliminary Screening Model 7-4
7.1.2 Selection of the AQCRs 7-11
7.1.3 Summary of Input Data and Evaluation Matrix 7-19
7.1.4 Results 7-46

7.2 Summary of Source/Control Priorities 7-61
7.3 Pollutant/Impact Screening 7-66
7.4 Future Effort 7-74

APPENDIX A — EMISSION INVENTORY

A.1 Noncriteria Pollutant Emission Factors A-1
A.2 Formulation of NO_x Emission Control Factors A-1
A.3 Emission Inventory A-6

APPENDIX B — 1973 NEDS FUEL USE AND EMISSIONS REPORTS FOR LOS ANGELES (024) AND CHICAGO (067) B-1

APPENDIX C — MOBILE SOURCE EMISSIONS C-1

APPENDIX D — DISPERSION MODELS FOR HEALTH EFFECTS D-1

D.1 Point Sources D-1

LIST OF ILLUSTRATIONS

Figure		Page
2-1	Sources of nitrogen oxide emissions	2-3
2-2	Utility boiler equipment population based on number of installed units	2-8
2-3	Firing method versus boiler size for pulverized coal-fired (dry bottom) utility boilers	2-9
2-4	Coal-fired utility boiler combustion process flow diagram	2-13
2-5	Utility boiler equipment categories	2-17
2-6	Packaged boiler equipment categories	2-23
2-7	Warm air furnaces and related combustion equipment	2-24
2-8	Important commercial and residential combustion equipment	2-31
2-9	Basic simple cycle gas turbine	2-32
2-10	Important gas turbine equipment types and their fuels	2-38
2-11	Important reciprocating IC engine equipment types and their fuels	2-43
4-1	Nitrogen and sulfur content of U.S. coal reserves	4-14
4-2	Conversion of fuel N in practical combustors	4-16
4-3	Possible fate of fuel nitrogen contained in coal particles during combustion	4-17
4-4	Conversion of nitrogen in coal to NO_x	4-19
4-5	Operating results of Scattergood unit No. 3 of LADWP; nitric oxide emissions below 35 ppm	4-41
4-6	1975 capital cost of OFA on new tangential coal-fired boilers	4-58
4-7	1975 capital cost of OFA on existing coal-fired boilers	4-59
4-8	Pyridine HDN with $NiMo/Al_2O_3$ catalyst	4-77
4-9	Hydrogen consumption versus nitrogen removal	4-78
5-1	Distribution of anthropogenic NO_x emissions for the year 1974 (stationary fuel combustion: controlled NO_x levels)	5-44
5-2	Distribution of stationary anthropogenic NO_x emissions for the year 1974 (stationary fuel combustion: controlled NO_x levels)	5-47
6-1	Effect of excess air on emissions from an oil-fired warm air furnace	6-21
6-2	Effect of derating on IC engine HC emissions	6-36
6-3	Effect of retarding ignition on IC engine HC emissions	6-36
6-4	Effect of air-to-fuel ratio on IC engine HC emissions	6-38
6-5	Effect of decreased manifold air temperature on IC engine HC emissions	6-39
6-6	Effect of water injection on IC engine HC emissions	6-39

LIST OF ILLUSTRATIONS (Concluded)

Figure		Page
6-7	Effect of combustion air swirl on solid emissions with oil combustion	6-43
6-8	Effect of NO_x controls on solid particulate emissions from industrial boilers	6-48
6-9	Effects of NO_x controls on particulate size distribution from oil-fired industrial boilers	6-49
6-10	Smoke levels versus NO_x levels for large bore diesel engines	6-51
6-11	Gas turbine particulate emissions as a function of load	6-53
6-12	Partitioning of Class I elements	6-57
6-13	Partitioning of Class II elements	6-58
6-14	Sulfate formation regimes of importance	6-64
6-15	SO_2 conversion vs. excess oxygen	6-67
7-1	Flow chart for the preliminary screening model	7-9
7-2	Distribution of a source into new and old equipment	7-28
7-3	Cumulative cost and reduction in ambient concentration for application of the controls in Table 7-31 (preliminary process data, Los Angeles, 2000, nominal growth, 1973 concentration = 132 $\mu g/m^3$)	7-54
7-4	Cumulative cost and reduction in ambient concentration for application of the controls in Table 7-32 (preliminary process data, Chicago, 2000, nominal growth, 1973 concentration = 96 $\mu g/m^3$).	7-55
A-1	Sample emission listing	A-7
C-1	Speed variation of speed adjustment factors for oxides of nitrogen	C-5

LIST OF TABLES

Table		Page
2-1	Design and Operating Characteristics of Utility Boilers	2-11
2-2	Combustion Related Effluent Streams from a Utility Boiler	2-14
2-3	Effect of Nonstandard Operating Procedures on the Effluent Streams from a Dry Bottom Pulverized Coal-Fired Boiler	2-16
2-4	Typical Design and Operating Characteristics of Packaged Boilers	2-21
2-5	Packaged Boiler Effluent Streams	2-22
2-6	Design and Operating Characteristics of a Typical 29 KW Gas-Fired Forced Air Furnace	2-28
2-7	Design and Operating Characteristics of a Typical 29 KW Oil-Fired Forced Air Furnace	2-29
2-8	Operating Characteristics of a Typical Electrical Utility Gas Turbine and a Combined Cycle Unit (Oil Fuel)	2-36
2-9	Typical Operating Characteristics of a Simple Cycle and a Regenerative Cycle Medium Capacity and a Simple Cycle Small Capacity Gas Turbine	2-37
2-10	Design and Operational Adjustments Which Affect Emissions for IC Engines	2-42
2-11	Significant Industrial Process Heating Equipment Types	2-48
2-12	Advanced Combustion Systems — State of Development	2-49
2-13	Significant Stationary Fuel Combustion Equipment Types/Major Fuels	2-58
3-1	Preliminary Pollutant Catalog	3-4
3-2	Methods for Determining Health Effects of Air Pollutants	3-15
3-3	Methods of Assessing Pollutant Impacts Upon Aquatic and Terrestrial Systems	3-24
3-4	Estimation of Concentrations for Screening Combustion-Generated Pollutants	3-30
3-5	Environmental Significance of Some Chemicals That May Exist in Airborne, Liquid, and Solid Effluents from Stationary Combustion Sources	3-45
4-1	Current or Planned Federal Standards of Performance for New Stationary Sources	4-4
4-2	Summary of State and Local NO_x Emission Standards	4-5
4-3	Factors Controlling the Formation of Thermal NO_x	4-13
4-4	Summary of Combustion Process Modification Concepts	4-21
4-5	Summary of Results with Low Excess Air Firing	4-23
4-6	Summary of Results with Flue Gas Recirculation	4-28
4-7	Summary of Results with Off-Stoichiometric Combustion	4-34
4-8	Summary of Results with Load Reduction	4-38

LIST OF TABLES (Continued)

4-9 Summary of Results with Burner Modifications 4-44

4-10 Summary of Results with Water Injection 4-49

4-11 Summary of Results with Reduced Air Preheat 4-52

4-12 Summary of Results with Ammonia Injection 4-56

4-13 1974 Estimated Investment Costs for Low Excess Air Firing on Existing Boilers Needing Modifications 4-61

4-14 1975 Installed Equipment Costs for Existing PG&E Residual Oil-Fired Utility Boilers 4-62

4-15 LADWP Estimated Installed 1974 Capital Costs for NO_x Reduction Techniques on Gas- and Oil-Fired Utility Boilers 4-64

4-16 1975 Differential Operating Costs of OFA on New and Existing Tangential Coal-Fired Utility Boilers 4-65

4-17 Cost Impacts of NO_x Controls for Large Bore Engines 4-68

4-18 Typical 1974 Baseline Costs for Large (>75 kW/Cylinder) Engines 4-69

4-19 Impact of NO_x Emission Control on the Installed 1975 Capital Cost of Gas Turbines 4-71

4-20 1975 Costs for Water Injection, Mills/kWhr 4-72

4-21 Hydrodesulfurization Performance of the Gulf Process 4-75

4-22 Solvent Refined Coal Tests 4-80

4-23 Fuel Additives with Possible Peripheral Benefits to NO_x Control Techniques in Boilers 4-83

4-24 Summary of FGT Processes 4-93

4-25 1974 Cost Estimates for Combustion Flue Gas Treatment Processes 4-97

4-26 Summary of NO_x Control Technology 4-98

4-27 Overall Evaluation of NO_x Control Techniques 4-102

5-1 Properties and Trace Elements of Representative Fossil Fuels 5-5

5-2 1974 Stationary Source Fuel Consumption 5-7

5-3 Utility Boiler Fuel Consumption (kJ x 10^{-15}) 5-8

5-4 1974 Packaged Boiler Fuel Consumption (kJ x 10^{-15}) 5-10

5-5 1974 Warm Air Furnace and Other Commercial/Residential Combustion (kJ x 10^{-15}) 5-12

5-6 1974 Gas Turbine Fuel Consumption (kJ x 10^{-15}) 5-12

5-7 1974 Reciprocating IC Engine Fuel Consumption (kJ x 10^{-15}) 5-14

5-8 1974 Industrial Process Heating Production 5-16

5-9 Utility Boiler Criteria Pollutant Emission Factors (ng/J) 5-18

5-10 Package Boiler Criteria Pollutant Emission Factors (ng/J) 5-20

LIST OF TABLES (Continued)

5-11 Warm Air Furnace and Miscellaneous Commercial and Residential Combustion Criteria Pollutant Emission Factors (ng/J) 5-23

5-12 Gas Turbine Criteria Pollutant Emission Factors (ng/J) 5-25

5-13 Reciprocating IC Engine Criteria Pollutant Emission Factors (ng/J) 5-26

5-14 Industrial Process Combustion Criteria Pollutant Emission Factors (g/kg Product) 5-28

5-15 Average Particulate Collection 5-30

5-16 NO_x Control Factors 5-32

5-17 1974 Criteria Pollutant Emissions for the Utility Boiler Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-34

5-18 1974 Criteria Pollutant Emissions for the Package Boiler Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-35

5-19 1974 Criteria Pollutant Emissions for the Warm Air Furnace and Misc-Combustion Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-36

5-20 1974 Criteria Pollutant Emissions for the Gas Turbine Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-37

5-21 1974 Criteria Pollutant Emissions for the Reciprocating I.C. Engine Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-38

5-22 1974 Criteria Pollutant Emissions for the Industrial Process Heating Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-39

5-23 Criteria Pollutant Emissions by Sector (Uncontrolled NO_x) 1,000 Mg/yr 5-40

5-24 Comparison of Controlled and Uncontrolled Stationary Source NO_x Emissions 5-41

5-25 Summary of 1974 U.S. Anthropogenic NO_x Emissions 5-43

5-26 Summary of 1974 Stationary Source NO_x Emissions by Fuel — 1,000 Mg (Percent of Total) 5-46

5-27 1974 Summary of Air and Solid Pollutant Emission from Stationary Fuel Burning Equipment (1,000 Mg) 5-48

5-28 Fuel Consumption Ranking of Stationary Combustion Sources 5-49

5-29 SO_x Mass Emission Ranking of Stationary Combustion Equipment 5-50

5-30 CO Mass Emission Ranking of Stationary Combustion Equipment 5-51

5-31 HC Mass Emission Ranking of Stationary Combustion Equipment 5-52

5-32 Particulate Mass Emission Ranking of Stationary Combustion Equipment 5-53

5-33 NO_x Mass Emission Ranking of Stationary Combustion Equipment and Criteria Pollutant and Fuel Use Cross Ranking 5-54

5-34 Comparison of Stationary Uncontrolled NO_x Emissions (1,000 Mg) 5-56

5-35 Comparison of Stationary Source Annual Fuel Consumption Estimates (10^{15} kJ) 5-58

5-36 Comparison of Current Stationary Emission Estimates Data with Previous Studies (1,000 Mg) 5-59

LIST OF TABLES (Continued)

6-1 Postulated Effect of Combustion Conditions on Flue Gas Emissions from Boilers 6-4

6-2 Postulated Overall Effect of Combustion NO_x Controls on Flue Gas Emissions from Boilers 6-10

6-3 Postulated Effects of Combustion Conditions on Emissions from IC Engines and Gas Turbines 6-13

6-4 Postulated Overall Effect of Combustion NO_x Controls on Emissions from IC Engines 6-16

6-5 Postulated Overall Effect of Combustion NO_x Controls on Emissions from Gas Turbines 6-18

6-6 Effect of Low-NO_x Operation on Incremental Emissions and System Performance for Residential Warm Air Furnaces 6-22

6-7 Representative Effects of NO_x Controls on CO Emission from Utility Boilers 6-24

6-8 Effects of NO_x Controls on CO Emissions from Industrial Boilers 6-28

6-9 Representative Effects of NO_x Controls on CO Emissions from IC Engines 6-31

6-10 Representative Effects of NO_x Controls on CO Emissions from Gas Turbines 6-32

6-11 Representative Effects of NO_x Controls on Vapor Phase Hydrocarbon Emissions from Industrial Boilers 6-35

6-12 Summary of the Effects of NO_x Controls on Vapor Phase Hydrocarbon Emissions from Gas Turbines 6-40

6-13 Effects of NO_x Controls on Particulate Emissions from Coal-Fired Utility Boilers 6-45

6-14 Effects of NO_x Controls on Emitted Particle Size Distribution from Coal-Fired Utility Boilers 6-46

6-15 Relationship Between Smoke, EGR, and Retard 6-52

6-16 Mechanisms that Convert Sulfur Dioxide to Sulfates 6-61

6-17 SO_x Summary 6-68

6-18 Summary of Process Modifications to Reduce Acid Smut Fallout 6-70

6-19 Summary of POM Emission Tests 6-73

6-20 Nitrate Formation Mechanisms 6-75

6-21 Evaluation of Incremental Emissions Due to NO_x Controls Applied to Boilers 6-77

6-22 Evaluation of Incremental Emissions Due to NO_x Controls Applied to IC Engines 6-78

6-23 Evaluation of Incremental Emissions Due to NO_x Controls Applied to Gas Turbines 6-79

LIST OF TABLES (Continued)

7-1 Summary of Available Air Quality Models 7-6

7-2 NO_x Impacted AQCRs and AQMAs (Rolling Quarters Average) 7-13

7-3 Air Pollution Characteristics of the NO_x Impacted AQCRs and AQMAs 7-16

7-4 Characteristic Groups of NO_x Impacted AQCRs and AQMAs 7-18

7-5 1973 NO_x Emissions and Fuel Use for Los Angeles, AQCR 024 7-21

7-6 1973 NO_x Emissions and Fuel Use for Chicago, AQCR 067 7-22

7-7 Maximum Annual Average NO_2 Concentration, Los Angeles, AQCR 024 7-23

7-8 Maximum Annual Average NO_2 Concentration, Chicago, AQCR 067 7-23

7-9 Annual Average NO_2 Concentration Used for Model Calibration ($\mu g/m^3$) 7-23

7-10 Average Growth Rates in Annual Fuel Use for Stationary Sources in Chicago, AQCR 067 7-25

7-11 Increase in Fuel Use in Future Years for Chicago, AQCR 067, 1973 Base 7-25

7-12 Average Growth Rates in Annual Fuel Use for Stationary Sources in Los Angeles, AQCR 024 7-27

7-13 Increase in Fuel Use in Future Years for Los Angeles, AQCR 024; 1973 Base 7-27

7-14 Equipment Retirement Rates 7-29

7-15 Mobile Source Emission Factors (g/km) and Annual Growth Rates 7-31

7-16 Mobile Source NO_x Emissions (All Values in Gg/yr Expressed as NO_2) 7-32

7-17 Fuel Costs in the Chicago AQCR, 1973-2000 7-33

7-18 Fuel Costs in the Los Angeles AQCR, 1973-2000 7-34

7-19 Cost of NO_x Controls for Coal-Fired Utility Boilers 7-36

7-20 Cost of NO_x Controls for Gas- and Oil-Fired Utility Boilers 7-37

7-21 Cost of NO_x Controls for Coal-Fired Industrial Watertube Boilers 7-38

7-22 Cost of NO_x Controls for Gas- and Oil-Fired Industrial Watertube Boilers 7-39

7-23 Cost of NO_x Controls for Gas- and Oil-Fired Industrial Firetube Boilers 7-40

7-24 Cost of NO_x Controls for Gas- and Oil-Fired Residential Furnaces 7-41

7-25 Cost of NO_x Control for Gas Turbines 7-42

7-26 Cost of NO_x Controls for IC Engines 7-43

7-27 Cost of NO_x Controls for Industrial Process Furnaces 7-44

7-28 Evaluation Matrix, Growth Scenarios 7-47

7-29 Evaluation Matrix: Base Year Concentration and Source Weighting Factors for Los Angeles 7-48

LIST OF TABLES (Continued)

7-30 Evaluation Matrix: Base Year Concentrations and Source Weighting Factors for Chicago 7-49

7-31 Control Prioritization for Los Angeles (2000, Equal Source Weighting) 7-51

7-32 Control Prioritization for Chicago (2000, Equal Source Weighting) 7-52

7-33 Summary of Control Levels Required to Meet NO_2 Standard in Los Angeles, AQCR 024 7-57

7-34 Summary of Control Levels Required to Meet NO_2 Standard in Chicago, AQCR 067 7-59

7-35 Evaluation of NO_x E/A Source Priorities 7-63

7-36 Summary of NO_x E/A Source/Control Priorities 7-67

7-37 Comparison of Pollutant Emission Levels with NO_x Controls to Maximum Allowable Emissions 7-69

7-38 Comparison of Baseline Pollutant Emission Levels to Maximum Allowable Emissions 7-70

7-39 Summary of Potential Pollutant/Combustion Source Hazards 7-73

A-1 Sector I Noncriteria Pollutant Emission Factors A-2

A-2 Metal Emission Factors (ng/J) — Sector I A-3

A-3 Packaged Boiler Sulfate and POM Emission Factors Liquid and Solid Ash Stream Generation Factors A-4

A-4 Warm Air Furnace POM Emission Factors A-5

A-5 Fuel Type Codes A-8

A-6 Emission Inventory — Group I Pollutants A-9

A-7 Emission Inventory — Group II Pollutants A-25

A-8 Emission Inventory — Group III Pollutants A-32

A-9 Emission Inventory — Group IV Pollutants A-39

B-1 NEDS Annual Fuel Summary for Chicago, AQCR 067 . . . . B-3

B-2 NEDS Annual Emissions Report for Chicago, AQCR 067 . . . . B-4

B-3 NEDS Annual Fuel Summary for Los Angeles, AQCR 024 . . . . B-8

B-4 NEDS Annual Emission Report for Los Angeles, AQCR 024 . . . . B-9

C-1 Vehicle Polutation and Annual Distance Traveled vs. Vehicle Age C-3

C-2 Deterioration Factors for Light-Duty Passenger Cars and Light-Duty Trucks C-4

C-3 Los Angeles AQCR Registered Vehicle Population C-7

C-4 Chicago AQCR Registered Vehicle Population C-8

C-5 Vehicle Distribution as a Percentage of all Registered Trucks and Automobiles C-10

LIST OF TABLES (Concluded)

C-6 Mobile Source Emission Factors g/km C-10

C-7 A Comparison of the Calculated Vehicle Population and the Registered Vehicle Population (1,000 Vehicles) C-10

C-8 Mobile Source Emission Factors (g/km) and Annual Growth Rates C-14

C-9 Mobile Source Emissions of Oxides of Nitrogen in the Los Angeles AQCR (Gg/year) C-15

C-10 Mobile Source Emissions of Oxides of Nitrogen in the Chicago AQCR (Gg/year) C-15

D-1 Sample Calculations of (Xu/e) Max for Point Sources in the Chicago AQCR D-3

SECTION 1
INTRODUCTION

Since the Clean Air Act of 1970, a moderate level of NO_x control has been developed and/or implemented for a variety of stationary combustion NO_x sources. Recently, however, EPA has determined that additional stationary source control technology is needed to maintain NO_2 air quality. The need for this additional technology is caused by the relaxation of mobile source standards, the increasing growth of stationary source NO_x emissions, and the consideration by the EPA of more stringent NO_2 air quality standards.

With more NO_x controls being implemented in the field and expanded control development anticipated for the future, there is currently a need to (1) ensure that the current and emerging control techniques are environmentally sound, and compatible with efficient and economical operation of systems to which they are applied and (2) ensure that the scope and the timing of the new control development program are adequate to allow stationary sources of NO_x to comply with potential air quality standards. The NO_x E/A program addresses these needs by (1) identifying the incremental multimedia environmental impact of combustion modification NO_x controls, and (2) identifying specific source/control combinations which will make it possible to maintain alternate ambient NO_2 standards in the most cost-effective manner to the year 2000 in NO_2-critical areas. As a prelude to the NO_x E/A program, this report documents the preliminary characterization and data evaluation of the equipment, controls, emissions, and environmental impacts to be considered in the program.

1.1 BASIS FOR CURRENT CONTROL TECHNOLOGY REQUIREMENTS

In 1971, following provisions of the 1970 Clean Air Act amendments, the EPA promulgated a primary and secondary National Ambient Air Quality Standard (NAAQS) for NO_2 of 100 $\mu g/m^3$ (annual average). Ambient NO_2 measurements made with the Jacob-Hocheiser Federal Reference Method in that year showed that 47 Air Quality Control Regions (AQCRs) were in violation of the standard. At that time, the EPA NO_x abatement strategy for attaining and maintaining the NAAQS for NO_2 relied heavily on NO_x controls for mobile sources. As mandated by the Clean Air Act, light duty vehicle (LDV) emissions were to be reduced by 90 percent to a level of 0.25 g NO_2/km (0.4 g/mile) by 1976. Stationary sources were to be regulated through EPA Standards of Performance for New Stationary Sources, which would be set as technology became available on the basis of the best system of emissions reduction. Additional standards for new or existing sources required to achieve air quality in the AQCRs would be set through the State Implementation Plans.

To support this abatement strategy, EPA set up a stationary source NO_x control development program. This program concentrated on controlling NO_x through combustion process modifications, since earlier studies by the National Air Pollution Control Administration (Reference 1-1) showed that this approach was the easiest to implement and the most cost effective. Because of the strong emphasis placed on controlling mobile sources at that time, a limited scope was set for the stationary source control development program. As a result, the stationary source program has focused on achieving a moderate level of control for conventional equipment categories readily amenable to combustion process modification. At the same time, equipment users and manufacturers have conducted programs for developing NO_x controls. The technology developed and/or disseminated by these programs in the EPA and the private sector has brought about widespread implementation of stationary source NO_x controls.

Stationary source NO_x controls have been applied to existing utility boilers, large industrial boilers and gas turbines in a number of areas as part of State Implementation Plans (see Section 4.1). As more areas regulate stationary sources and smaller equipment is brought under regulation in some areas, the trend is to widespread use of retrofit NO_x controls. In addition, new sources with factory-installed NO_x controls are being commissioned in compliance with the EPA Standards of Performance for New Stationary Sources set in 1971 for large steam generators firing gas, oil and coal (except lignite). A standard for lignite coal firing and a more stringent standard for bituminous coal firing have been recommended. Draft standards for gas turbines and stationary IC engines are in preparation and standards for intermediate boilers are under study.

This increasing regulation of both new and existing sources of NO_x emissions points, in the 1980's, to widespread implementation of moderate NO_x controls on major equipment types. Furthermore, these moderate NO_x controls correspond to the moderate level of technology being generated in the control development program in accordance with the original NO_x abatement strategy. Recent reappraisals of this abatement strategy, however, have raised questions about whether or not this degree of control development and implementation is adequate to meet NO_2 air quality goals.

1.2 ANTICIPATED CONTROL TECHNOLOGY REQUIREMENTS

In the past 3 years, several developments have brought about changes in the national NO_x abatement strategy:

- Reclassification of AQCRs violating the NO_2 NAAQS
- Relaxation of the LDV NO_x standards
- Projections of continued rapid growth of stationary NO_x sources
- Increasing use of coal in stationary sources
- Emergence of advanced energy systems with potential environmental problems
- Consideration of additional NO_2 air quality standards

These developments have, in turn, changed the existing implementation requirements for NO_x controls — or added new requirements — for accomplishing the three goals of the abatement strategy:

- Attain the current NAAQS
- Maintain the current NAAQS
- Attain and maintain anticipated new NO_2-related air quality standards

The current thinking on anticipated implementation requirements for controls in each of these areas is reviewed below.

1.2.1 Attainment of NAAQS

The outlook for attaining the NAAQS has actually improved. In 1973, the EPA announced that the Federal Reference Method for ambient NO_2 measurement had in many cases been overestimating NO_2 concentrations (Reference 1-2). Using other analytical techniques, EPA remeasured air quality in the 47 AQCRs where the standards were suspected of being violated. The results showed that only five regions (Los Angeles, New York, Chicago, Denver, Salt Lake City) were violating the standards. Subsequent measurements with the new Federal Reference Method (chemiluminescent analyzer) or equivalent have shown that as many as 16 AQCRs may have annually-averaged NO_2 levels equal to or greater than the NAAQS (Reference 1-3). However, of the AQCRs in violation, only the South Coast Air Basin in the Los Angeles area has a severe problem. There, NO_x emission regulations have been set for new and existing utility boilers, large industrial boilers, and gas turbines.

In spite of the fact that the NO_x control problem is not as severe as originally estimated nationwide, it has recently been determined that additional NO_x controls will have to be implemented in the South Coast Air Basin to attain and maintain NO_2 air quality (Reference 1-4). Source/control options are currently being evaluated to define the most cost-effective regulatory approach. These near-term control requirements appear to be largely covered by the current NO_x control development program. Ultimate attainment may, however, require more advanced control technology than is being generated by the current development program (see Section 7 and References 1-5, 1-9).

1.2.2 Maintenance of NAAQS

The fact that the attainment of NAAQS will be less difficult than anticipated has caused the emphasis for maintenance to shift from mobile source control to stationary source control. Because of the errors in the Federal Reference Method, in 1973 the EPA Administrator delayed implementation of the light duty vehicle statutory standard — 0.25 g/km (0.4 g/mile) — and set an interim standard at 1.25 g/km (2.0 g NO_2/mile). Subsequently the Energy Supply and Environmental Coordination Act of 1974 delayed the statutory LDV standard to 1978 and maintained the interim standard at 1.25 g/km. The Clean Air Act Amendments of 1977, passed by Congress in August, further extend the emission schedule as follows:

1977 through 1980 — 1.25 g NO_2/km (2.0 g/mile)
1981 on — 0.62 g NO_2/km (1.0 g/mile).

The earlier statutory standard of 0.25 g/km is retained as a research objective for manufacturers.

Several studies have evaluated the impact that these changes in mobile source NO_x regulation will have on the overall NO_x abatement strategy. EPA's Office of Air Quality Planning and Standards (OAQPS) conducted a study in 1973 to analyze the NO_x abatement strategy in view of changes in air quality data and source growth projections. The OAQPS report (Reference 1-5) concluded: (1) the statutory LDV standard is not needed in most areas to attain and maintain the NAAQS; (2) in the 1980's, more control of stationary sources will be needed to maintain the NAAQS; and (3) control of stationary sources will be more effective and less costly in the 1980's than extensive control of mobile sources. As a result of this study, OAQPS recommended that the stationary source NO_x control program be expanded to generate the additional technology needed to maintain air quality.

Subsequent studies reinforced these conclusions on the combined effect of stationary source growth and the relaxation of the LDV standard. Projections of the growth of stationary sources nationwide (References 1-6, 1-7) showed that even with vigorous implementation of best available control technology through Standards of Performance for New Stationary Sources, nationwide NO_x emissions would increase by at least 25 percent by 1990. This study, and a recent EPA assessment of air quality maintenance strategies, (Reference 1-8) concluded that increased controls for stationary sources must be implemented.

Another study of the air quality impact of LDV emission controls and source growth (Reference 1-9) conducted by EPA and the Department of Transportation (DOT) also showed that NO_2 air quality violations will increase unless more stringent stationary source controls are applied. Of 10 cities analyzed in this study, at least 6 are projected to fail to maintain the NAAQS in 1985, even with the most restrictive mobile source standards. This projected failure is attributed to the expected increase in source emissions as well as to the moderate level of control mandated for these sources. The study also examines the cost-effectiveness, on a national basis, of several mobile and stationary source control options. Although the cost data will be subject to revision as better process studies become available, the results show that control of stationary sources to a level of 50 to 75 percent below uncontrolled levels is four times more cost-effective than reduction of LDV emissions from 1.25 g/km (2 g/mile) to 0.25 g/km (0.4 g/mile).

An additional factor in the maintenance of NO_2 air quality is the increasing use of coal in stationary sources as part of the National Energy plan. Coal typically has a higher NO_x emission potential than other fuels. Both the Energy Supply and Environmental Coordination Act (Reference 1-10) and Senate Bill 977 (Reference 1-11) mandate extensive use of coal in new and existing large combustion sources to reduce our dependence on imported oil. This increased use of coal, coupled with projected utilization of high-nitrogen shale oil, could have a dominant effect on future stationary source NO_x emissions (Reference 1-12). Along with this increased use of coal, a number of advanced energy systems are being developed to efficiently use coal or coal-derived fuels. The increased use of coal and the application of the advanced energy systems within acceptable environmental limits will require the use of advanced NO_x control techniques.

In summary, recent analyses of the requirements for maintaining NAAQS point to the need for developing and implementing more advanced NO_x controls for the 1980's and 1990's than was previously thought. The reevaluation of the LDV standard, the projected growth of stationary sources, and increased emission from the use of coal are the main factors in this change of strategy.

1.2.3 Attainment and Maintenance of Additional NO_2 Standards

While the above discussion deals with the requirements for stationary source controls to achieve and maintain the current NAAQS (100 $\mu g/m^3$, annual average), there is also the possibility that separate NO_x control requirements will be needed to attain and/or maintain additional NO_2-related standards. The current NAAQS was based on the fact that long-term exposure to NO_2 increases human susceptability to chronic respiratory infection (Reference 1-13). Short-term impacts of NO_2 on human health and the role of NO_2 in photochemical smog formation were not included in setting the standard. Recent data on the health effects of NO_2 suggest that the current NAAQS should be supplemented with a limitation on short-term exposure (References 1-8 and 1-14 to 1-16), and the Clean Air Act Amendments of 1977 require that the EPA consider setting a short-term NO_2 standard for a period not to exceed 3 hours. The OAQPS will consider the basis for a short-term standard, as well as potential revisions to the current standard, in 1978 when the NO_2 air quality criteria document (Reference 1-13) is updated (References 1-17, 1-18).

For the longer term, EPA is continuing to evaluate the need for additional NO_x regulation as part of the oxidant control strategy or for control of pollutants for which NO_x is a precursor, e.g., nitrates and nitrosamines (References 1-8, 1-16, 1-17, 1-18, 1-20). The Clean Air Act Amendments of 1977 require the National Commission on Air Quality to analyze the health effects of pollutants which are derivatives of oxides of nitrogen. Potential regulations resulting from these studies could be in the form of source emission controls or additional ambient air quality standards. In either case, additional stationary source control technology could be required to comply with the standards.

1.3 REQUIREMENTS FOR NO_x CONTROL TECHNOLOGY DEVELOPMENT

The need to develop NO_x control technology can be divided into two areas: (1) near-term application of existing technology, and (2) far-term development and implementation of advanced techniques not covered by the current development program.

In answer to the first of these needs, the present control development program is demonstrating the effectiveness of moderate combustion modification controls on major equipment types. At the same time, the economic, energy, and operational impacts of these controls are being identified. Recently, the need to assess the possible effect of NO_x controls on other pollutants and their eventual impact on the environment has also been emphasized. In fact, the assessment of the environmental impact of both energy systems and pollutant control systems has taken on a major role in the EPA/ORD R&D program, as is clearly shown by the extensive assessment activity discussed in the preface of this report.

To meet far-term needs, development of new control technology will be apparently needed to meet the more stringent and widespread control requirements suggested in current planning studies. This would require an expanded control development program including:

1. Greater levels of control for major design types
2. Controls for secondary design types not currently considered
3. Controls for alternate fuels and advanced energy systems planned for the 1980's and 1990's.

1.4 PURPOSE OF THE NO_x E/A

The NO_x E/A directly supports both the near- and far-term needs described above through two main activities. First, it will provide comprehensive process engineering and environmental assessment studies of both current and emerging combustion modification techniques. These studies will show the environmental, economic, energy, and operational impacts of achieving a given level of control for major stationary sources of NO_x. For current technology, these impacts can be considered in the selection of control techniques. For advanced technology, the control development program can be planned with these impacts clearly in mind.

Second, systems analyses will be conducted of the impact of the application of combustion modification controls on ambient NO_2 air quality. These system analyses will show which combination of control techniques is most effective in achieving alternate air quality goals in specific AQCRs. These results are intended for guidance of the second requirement in Section 1.3. Additionally, these results will set the scope of the process engineering and environmental assessment efforts within the NO_x E/A. The overall approach of the NO_x E/A is discussed in the Preface.

1.5 PURPOSE OF THIS REPORT

The NO_x E/A activities documented in this report began with compiling and evaluating data and defining the program approach and priorities. The initial activity was thus a first-pass review of existing data and techniques for all areas of the program. As discussed in the Preface, the subsequent effort will focus on generating new results in specific support tasks. This preliminary report will serve to initiate these efforts and to establish the approach and level of effort to be used in various subtasks. The objectives of this report are to (1) document the scope of the NO_x E/A in terms of sources, pollutants, impacts, and controls to be considered; (2) evaluate data on impact criteria, control effectiveness, baseline multimedia emissions, and incremental impacts of NO_x controls; and (3) define preliminary priorities on source/control combinations and effluent stream/impacts to be considered.

The report is structured according to these objectives. Sources of NO_x, pollutants and their impact, and stationary source NO_x controls are reviewed in Sections 2, 3, and 4 respectively. Data on multimedia impact criteria, control status and effectiveness, baseline emissions, and the incremental multimedia impact of NO_x controls are summarized in Sections 3, 4, 5, and 6. Some preliminary screening and prioritization in these areas are also done in these sections. The main conclusions from the data of Sections 2 through 6 and the preliminary definition of priorities for the NO_x

7

E/A are summarized in Section 7. Specific subobjectives addressed in the subsequent sections are as follows:

- Establish categories of stationary fuel combustion NO_x sources to be assessed in the NO_x E/A (Section 2)
- Identify source effluent streams and operating modes for which the emissions may be perturbed by the use of NO_x controls (Section 2)
- Establish a preliminary set of pollutants and their impacts to be considered in the source/control environmental assessments (Section 3)
- Compile and evaluate dose/response data on multimedia pollutant impact; tabulate impact criteria for use in preliminary screening of the impact of source/effluent stream/control combinations (Section 3)
- Identify possible approaches and problems in conducting a generalized (nonsite specific) impact assessment (Section 3)
- Survey available NO_x control techniques and specify the combustion modification technology to be addressed in the program (Section 4)
- Evaluate the status, effectiveness, cost, and operational impact of current and emerging combustion modification techniques (Section 4)
- Compile and evaluate NO_x emissions data for all NO_x sources; generate controlled nationwide NO_x inventory (Section 5)
- Compile and evaluate emission data on pollutants other than NO_x for stationary fuel combustion NO_x sources; generate nationwide emissions inventory (Section 5)
- Evaluate the effect of NO_x controls on emissions of pollutants other than NO_x (Section 6)
- Define preliminary source/control priorities based on projected control implementations requirements (Section 7)
- Define preliminary effluent stream/pollutant priorities based on potential impact resulting from the use of NO_x controls (Section 7).

REFERENCES FOR SECTION 1

1-1. Bartok, W., et al., "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources, Vol. II," Prepared for National Air Pollution Control Administration, NTIS-PB 192 789.

1-2. Federal Register Volume 38, No. 110, June 8, 1973, pp. 15174-15185.

1-3. Personal communication with E. Lewis, Office of Air Quality Planning and Standards, U.S. EPA, September 3, 1975.

1-4. "Progress Report — Control Strategy for Oxides of Nitrogen in the South Coast Air Basin," California Air Resources Board, Memo No. 76-16-4, August 24, 1976.

1-5. Crenshaw, J. and A. Basala, "Analysis of Control Strategies to Attain the National Ambient Air Quality Standard for Nitrogen Dioxide." Presented at the Washington Operation Research Council's Third Cost Effectiveness Seminar, Gaithersburg, Md., March 18-19, 1974.

1-6. Hopper, T. G. and W. A. Marrone, "Impact of New Source Performance Standards on 1985 Emissions from Stationary Sources." The Research Corporation, May 1975.

1-7. McCutchen, G. D., "NO_x Emission Trends and Federal Regulation," presented at AIChE 69th Annual Meeting, Chicago, Nov. 28 - Dec. 2, 1976.

1-8. "Air Program Strategy for Attainment and Maintenance of Ambient Air Quality Standards and Control of Other Pollutants," Draft Report, U.S. EPA, Washington, October 18, 1976.

1-9. "Air Quality, Noise and Health — Report of a Panel of the Interagency Task Force on Motor Vehicle Goals Beyond 1980," Department of Transportation, March 1976.

1-10. "Energy Supply and Environmental Coordination Act," Public Law 93-319.

1-11. "National Petroleum and Natural Gas Conservation and Coal Conversion Act of 1975," Senate Bill 977 (first introduced as 1777 on May 20, 1975).

1-12. Sarofim, A. F., et al., "Mechanisms and Kinetics of NO_x Formation: Recent Developments," presented at the 69th Annual Meeting, AIChE, Chicago, Illinois, November 1976.

1-13. "Report on Air Quality Criteria for Nitrogeh Oxides," AP-84, Science Advisory Board, U.S. EPA, June 1976.

1-14. Stephens, R. H., et al., "Standard Support and Environmental Impact Statement for Standards of Performance: Lignite-Fired Steam Generators." EPA Office of Air Quality Planning and Standards, March 1975.

1-15. "Scientific and Technical Data Base for Criteria and Hazardous Pollutants — 1975 ERC/RTP Review," EPA-600/1-76-023, NTIS-PB 253 942/AS, Health Effects Research Laboratory, U.S. EPA, January 1976.

1-16. French, J. G., "Health Effects from Exposure to Oxides of Nitrogen," presented at the 69th Annual Meeting, AIChE, Chicago, Illinois, November 1976.

1-17. "Control Strategy for Nitrogen Oxides," memo from B. J. Steigerwald, Office of Air Quality Planning and Standards, September 1976.

1-18. "Report on Air Quality Criteria: General Comments and Recommendations," Report to the U.S. EPA by the National Air Quality Advisory Committee of the Science Advisory Board, June 1976.

1-19. Personal communication with M. Jones, Strategies and Air Standards Division, Pollutant Strategies Branch, September 15, 1976.

1-20. "Control of Photochemical Oxidants — Technical Basis and Implications of Recent Findings," EPA 450/2-75-005, EPA Office of Air and Waste Management, OAQPS, July 1976.

1-21. "Scientific and Technical Assessment Report on Nitrosamines," EPA 600/6-77-001, EPA Office of Research and Development, November 1976.

SECTION 2

NO_x SOURCE CHARACTERIZATION

This section presents a preliminary characterization of NO_x sources for use in prioritizing and simplifying the environmental assessment and process engineering efforts in this program. The main objective of this preliminary characterization is to categorize equipment design according to characteristics which affect the formation and/or control of multimedia pollutants. Emphasis is on stationary combustion sources of NO_x. However, the remaining sources of NO_x are also of interest in this program, since the degree of control for emissions from these sources governs the extent to which NO_x controls are needed for stationary combustion sources. The equipment categories described in this section will be used as the basis of the emission inventory in Section 5 and the preliminary source prioritization in Section 7. Subsequently, these categories will be further refined as part of the process engineering studies in Task B5 (see Preface).

In order to make this preliminary characterization of NO_x sources, the following steps were taken:

- Identify significant sources of NO_x; group according to formative mechanism and nature of release into the atmosphere
- Categorize stationary combustion sources according to equipment and/or fuel characteristics affecting the generation and/or control of combustion-generated pollution
- Qualify equipment fuel categories on the basis of current and projected use and design trends; develop a provisional list of equipment/fuel combinations to be carried through the subsequent emission inventories, process studies, and environmental assessments
- Identify effluent streams from stationary combustion source equipment/fuel categories which may be perturbed by the use of NO_x combustion modification controls
- Identify operating modes (transients, upsets, maintenance) for which the emissions may be perturbed by NO_x combustion modification controls

The following paragraphs summarize the approach used in each step of this sequence.

Significant sources of NO_x have been identified in several previous studies (References 2-1 through 2-5). These sources are grouped in Figure 2-1 according to the way NO_x is released into the atmosphere and the mechanisms leading to its formation. Primary emphasis in the NO_x E/A is on the seven major categories of stationary fuel combustion sources bracketed on the figure:

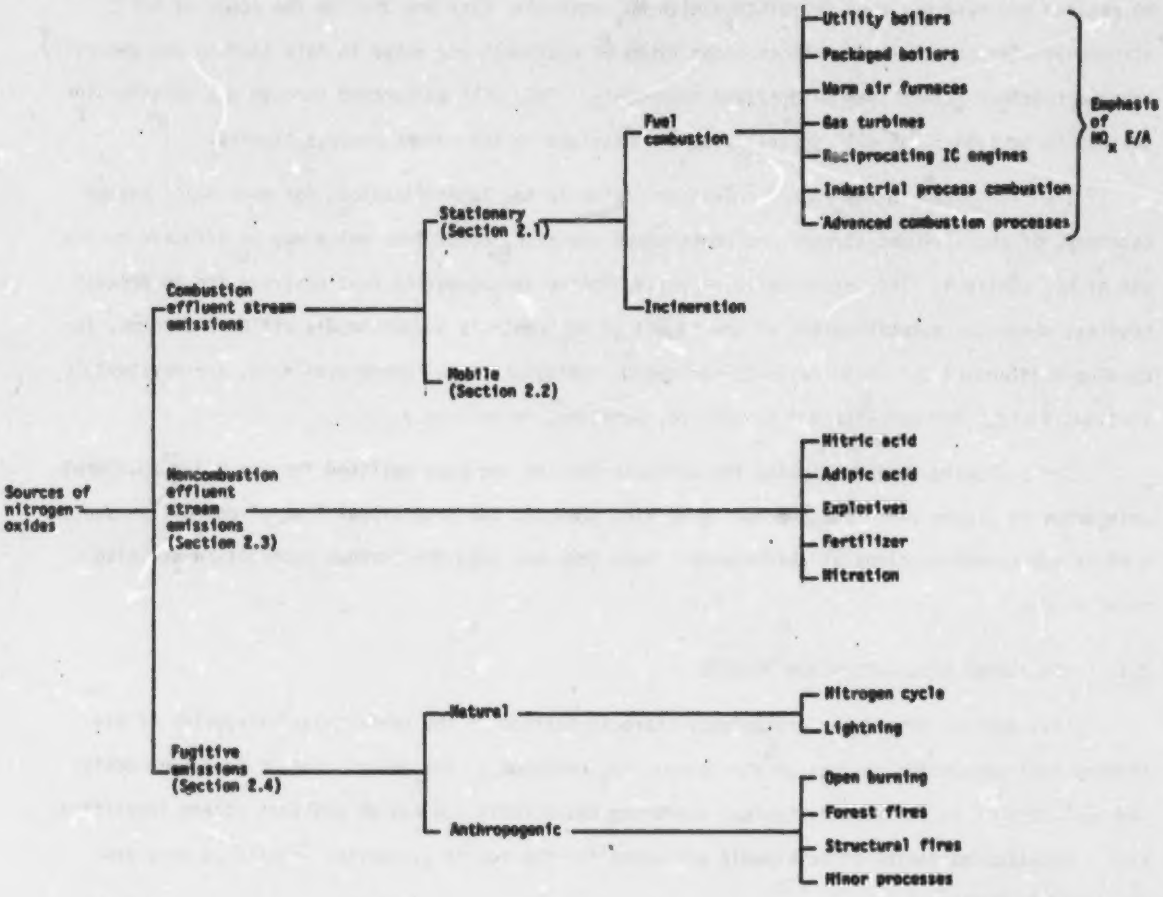
- Utility and large industrial boilers >73 MW (250 x 10^6 Btu/hr) heat input
- Industrial and commercial packaged watertube and firetube boilers
- Commercial and residential warm air furnaces
- Utility and industrial gas turbines
- Reciprocating IC engines
- Industrial process combustion equipment
- Advanced combustion processes

The remaining sources will be considered only as required to determine the relative amount of NO_x contributed by combustion sources on a regional or national basis.

The major source category groupings in Figure 2-1 are broad, particularly for stationary fuel combustion sources, in that they each encompass a number of design variations and fuels. Since many of these design variations affect the emission rates of combustion-generated pollutants and the applicability and effectiveness of NO_x controls, they may merit separate consideration in the emission inventories and environmental assessments. The stationary fuel combustion source groupings are therefore further subdivided in this section according to the following factors which are known to influence combustion-generated air pollution:

- Combustion chamber configuration
- Combustion intensity
- Temperature-time history of combustion gases
- Aerodynamics of fuel-air mixing
- Fuel composition (bound nitrogen, trace elements) and combustion conditions (flame temperature, excess air requirements)

Where possible, these factors are interpreted in light of existing source emission data and experience in applying NO_x controls to determine appropriate source categories. These data are reviewed in Sections 4 and 5.



Sources of nitrogen oxides
Combustion effluent stream emissions
Stationary (Section 2.1)
Fuel combustion
Utility boilers
Packaged boilers
Warm air furnaces
Gas turbines
Reciprocating IC engines
Industrial process combustion
Advanced combustion processes
Emphasis of NO_x E/A
Incineration
Mobile (Section 2.2)
Noncombustion effluent stream emissions (Section 2.3)
Nitric acid
Adipic acid
Explosives
Fertilizer
Nitration
Fugitive emissions (Section 2.4)
Natural
Nitrogen cycle
Lightning
Anthropogenic
Open burning
Forest fires
Structural fires
Minor processes

Figure 2-1. Sources of nitrogen oxide emissions.

The number of equipment/fuel combinations resulting from this categorization is far too large (approximately 150) to treat comprehensively at the same level of detail in this program. Accordingly, preliminary prioritization of these equipment/fuel combinations is undertaken in Section 7, based on the quantification of source emissions and the evaluation of the potential applications of NO_x control for various equipment/fuel types. In addition, some preliminary screening of equipment and fuels can be done in advance. There are a number of equipment designs in the field which are no longer being manufactured. Since the bulk of these sources are scheduled to be retired and have not been retrofitted with NO_x controls, they are outside the scope of the environmental assessment study. These older types of equipment are noted in this section and generally grouped together rather than categorized separately. They will be carried through the emission inventory in Section 5 but will generally be deemphasized in subsequent process studies.

The final step in the source characterization is the identification, for each major source category, of the effluent streams and nonstandard operating conditions which may be affected by the use of NO_x controls. This exercise is a prelude to the subsequent B3 test programs and B5 process studies, where the quantification of the impact of NO_x controls on multimedia effluent streams, including nonstandard operation, will be addressed. Emissions data, where available, are reviewed in Sections 4 and 6 for baseline and controlled operation, respectively.

The following sections follow the characterization sequence outlined for the major equipment categories in Figure 2-1. The concluding section presents the provisional list of combustion sources used in subsequent sections of this report. Data gaps and need for further compilation are also pointed out.

2.1 STATIONARY FUEL COMBUSTION SOURCES

This section provides a preliminary characterization of the seven major categories of stationary fuel combustion sources of atmospheric NO_x emissions. The description of equipment design and applications is followed by typical operating characteristics and an effluent stream identification. Detailed estimates of multimedia effluents for the source categories identified here are presented in Section 5.

2.1.1 Utility and Large Industrial Boilers >73 MW (>250 MBtu/hr) Heat Input

For purposes of this study, the utility and large industrial boiler category will encompass all field-erected watertube boilers with a heat input greater than 73 MW (250 MBtu/hr) corresponding to an electrical generating capacity of about 25 MW. This category includes the vast majority of field-erected boilers used for utility or industrial electric power generation. Some industrial boilers used for process steam extend into the utility boiler capacity range. Also, some utility and industrial field-erected units, particularly older installations, have input capacities below the 73 MW specification. In both cases, however, the designs are generally similar to the smaller utility boilers within the above capacity range. For purposes of estimating emissions and evaluating the applicability of NO_x controls, these designs can therefore be effectively grouped with the utility boilers. Field-erected watertube boilers operate at steam temperatures up to 840K (1,050F) and steam pressures up to 26 MPa (3,800 psi). Although depending upon manufacturer, most units greater than about 750 MW operate at supercritical steam pressures above 24 MPa (3,500 psi) (Reference 2-6). Utility boilers recover up to 90 percent heat by a water-walled combustion chamber in combination with superheaters, reheaters, economizers, and air preheaters, with about half the heat being absorbed by radiant heat transfer to the furnace walls.

Fuels used in utility boilers include pulverized bituminous, subbituminous, and lignitic coals; residual and crude oils; and natural gas. Coals are burned in either dry bottom or wet bottom (slag tap) furnaces. Dry bottom furnaces operate at bulk furnace temperatures below the ash fusion point and ash is removed as a solid. Wet bottom furnaces melt the ash and remove slag through a bottom tap. Although wet bottom furnaces were once popular for burning slagging coals with low ash-fusion temperatures, they are no longer being manufactured due to operational problems with low sulfur coals and because their high combustion temperatures promote NO_x formation. As a result, wet bottom furnaces will generally be treated as a subset of each specific equipment type rather than treated separately.

Although coal, residual oil, and natural gas are the main fuels used in field-erected watertube boilers, process gas and solid wastes are sometimes burned. These secondary fuels are burned almost exclusively in the industrial applications, where product gases or waste fuels are produced as by-products of the industrial process, and where fuel quality is of less importance. Coal, natural gas, and petroleum products accounted for 56.4 percent, 25.5 percent, and 18.1 percent of the total fuel consumption in large watertube boilers in 1974. About 85 percent of this fuel was used to generate electricity.

The major combustion-related difference between boilers in this sector is furnace design. Four major manufacturers supply the following primary burner/furnace configurations:

- Tangential-firing (Combustion Engineering, Inc. — CE)
- Single-wall firing (Foster Wheeler Energy Corp. — FW, Babcock and Wilcox Co. — B&W, Riley Stoker Corp. — RS)
- Horizontally-opposed wall-firing (B&W, FW)
- Turbofurnace (RS)

In a tangential furnace, arrays of fuel and air nozzles are located at the same elevation in each of the four corners of the combustion chamber. Each nozzle is directed tangentially to a small firing circle in the center of the chamber. The resulting spin of the four "flames" creates high turbulence and thorough mixing of fuel and air in the combustion zone. Additional levels of nozzles are mounted 2 to 3.5 meters apart for larger capacity furnaces.

In single-wall firing furnaces, burners are mounted normal to a single furnace wall. These units are typically limited in output capacity to about 400 MW because of furnace wall area. When larger capacity is required, horizontally-opposed wall-firing furnaces are normally used. Boilers with single wall firing tend to be older on the average than opposed wall firing boilers as a result of recent trends towards boilers with larger capacity.

In horizontally-opposed wall-firing furnaces, burners are mounted on opposite furnace walls. This is the most recently developed firing configuration, and is found on the newer units. Due to capital costs of fuel handling equipment, opposed-wall firing furnaces are limited to the larger (>400 MW output) boilers (Reference 2-6). Riley Stoker Corporation manufactures a version of the horizontally-opposed wall-firing furnace under the Turbofurnace label with burners mounted on downward inclining furnace walls.

Individual burners on single and opposed wall units are usually of the register type and have capacities in the 22 MW (~75 MBtu/hr) to 48 MW (~165 MBtu/hr) range; up to 72 burners can be mounted on the furnace walls. The pulverized coal is entrained by about 20 percent of the primary air and introduced into the combustion chamber at a velocity of about 25 m/s (~80 ft/s) where turbulent mixing with the remainder of the combustion air occurs. Natural gas is injected at velocities up to sonic through nozzles located in the register throat. Residual oil is preheated and injected through atomizers using high pressure steam (~95 percent of sales), air (~1 percent of sales) or mechanical means (~4 percent of sales) (Reference 2-7). For all of these fuels, secondary preheated 395 to 590K (250F to 600F) air enters at speeds of about 60 m/s (~200 ft/s) for oil and gas and about 37 m/s (~120 ft/s) for pulverized coal (Reference 2-8).

Three other firing methods exist but are seldom encountered in new utility-size units: stokers (B&W, CE, FW, RS), cyclone furnaces (B&W), and vertical-firing units (CE). Cyclone furnaces were being sold as late as 1974, but because the units have not proven adaptable for emissions reasons, sales have halted. Cyclone furnaces were originally developed by B&W to burn low ash fusion temperature, Illinois coal, but they have recently been used successfully with lignite. In this design, fuel and air are introduced circumferentially into the water-cooled cyclone furnace to produce a highly swirling, high temperature flame. The cyclone furnace must operate at high combustion temperatures (Reference 2-9), since it is designed to operate as a slagging furnace. Since high temperatures result in high thermal NO_x formation, the cyclone furnace has lost its market. In spite of this, cyclone furnaces will be discussed in subsequent sections of this report because of the relatively high number being used in the North Central area of the U.S.

Vertical-firing furnaces were developed for pulverized fuels before the advent of water-walled combustion chambers. They were previously used to a limited degree to fire anthracite coal. Anthracite, because of its low volatile content, is difficult to burn in conventional boilers. The long residence time resulting from the downward firing pattern in vertical furnaces was effective in achieving ignition and char burnout for anthracite. With the decline of anthracite as a utility fuel, vertical furnaces are no longer sold and few are found in the field. Stoker-fired furnaces for utilities are also seldom found in the field, primarily due to the trends toward larger capacity boilers. Design capacity limitations and high costs have made the stoker uncommon in utility boilers. In the interest of complete emission totals, vertical firing and stoker-fired boilers will be included in Section 5 as a single equipment type.

The distribution of utility boilers by firing type and fuel for 1974 is shown in Figure 2-2. The totals listed were derived from a systems study by GCA (Reference 2-10) and a boiler inventory by Battelle (Reference 2-11). Power Magazine Plant Design Surveys (Reference 2-12) were used to update the GCA data to 1974, and the Monsanto Research Corporation's Cyclone Boiler study (Reference 2-9) was also consulted for this firing type.

Figure 2-2 is based on number of installed units of each design type. Because of differences in average capacity among the different designs, it does not accurately reflect the distribution by installed capacity.

The alternate picture of distribution by installed capacity is shown in Figure 2-3 for coal-fired boilers. Note that tangential-firing, wall-firing, and opposed-wall-firing units account for 40 percent, 36 percent, and 14 percent of the fuel consumed by utility boilers. The trend of the last 10 years to larger capacities appears to have slowed, with many utilities electing to install two small boiler units rather than a single larger unit. The trend to larger boiler capacities brought with it the use of combustion chamber division walls. This increased the available heat transfer surface and essentially yielded two smaller combustion chambers with aerodynamic and combustion characteristics similar to smaller units. Large coal-fired furnaces, however, have generally not used division walls, because they cannot readily be cleaned by soot blowing (Reference 2-6).

17

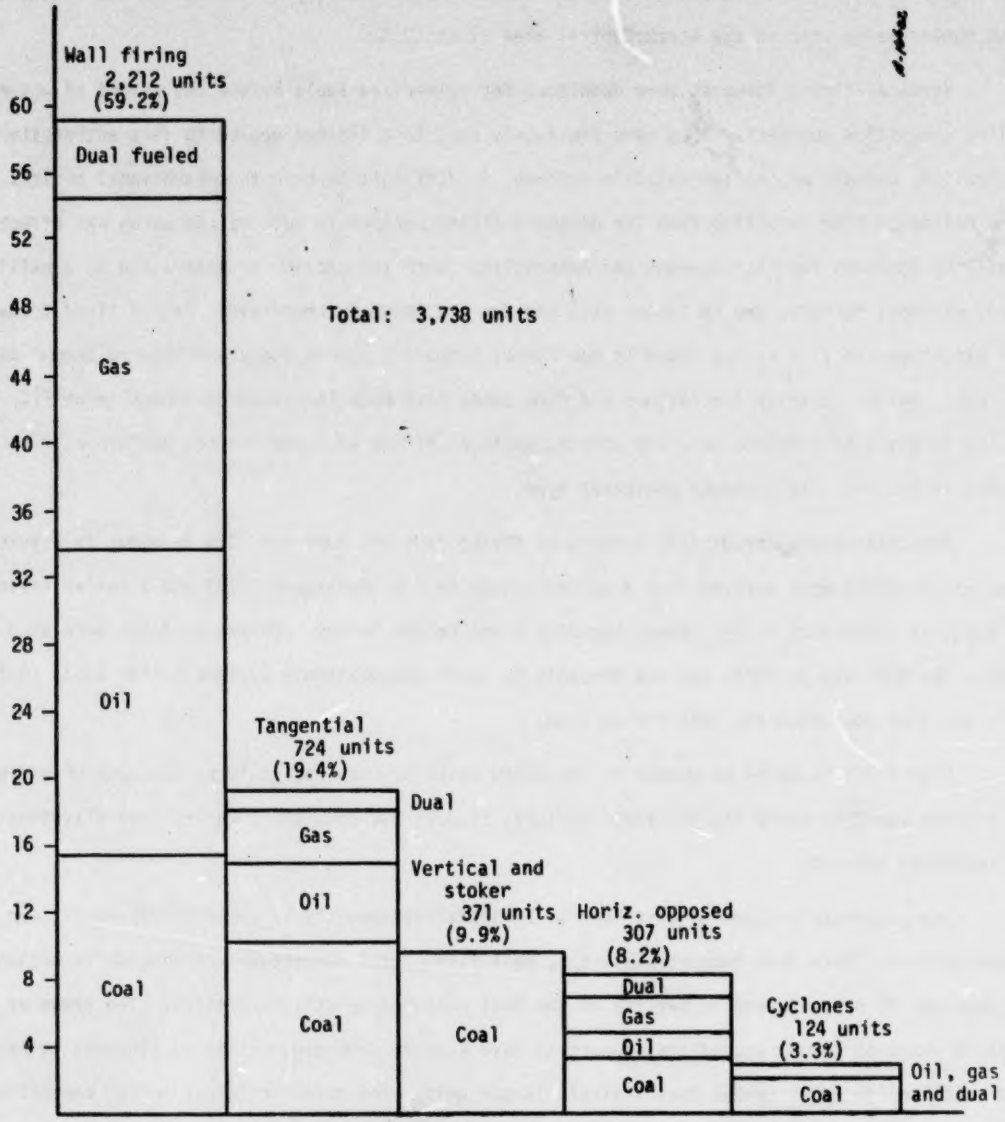


Figure 2-2. Utility boiler equipment population based on number of installed units (Reference 2-10).

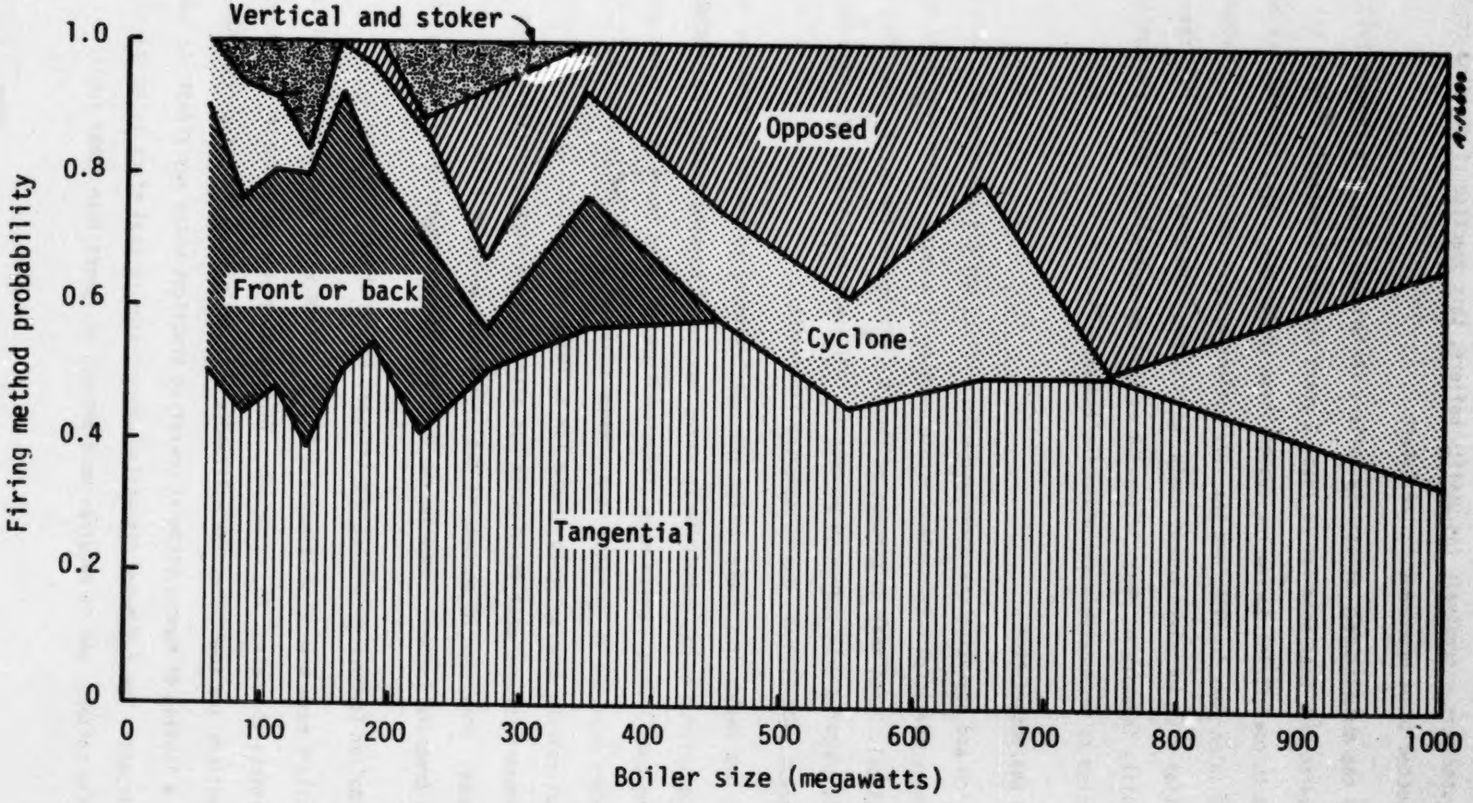


Figure 2-3. Firing method versus boiler size for pulverized coal-fired (dry bottom) utility boilers (Reference 2-13).

Since coal will be used more extensively for utility boilers, this practice of dividing combustion chambers is not expected to be prominent in the future.

According to the manufacturers of utility boilers (References 2-6, 2-14 through 2-17), no oil- or gas-fired units have been sold for at least 2 years and many previously ordered oil units have been converted to coal-firing during the design phase (Reference 2-6). The industry had a particularly depressed sales year in 1976, and the 1977 outlook appears equally dismal. Economic recession in combination with increased energy costs, mild summer load peaks, and a 1975 reserve capacity of the utility industry of about 37 percent as well as uncertainty about the nation's energy policy have acted to produce this situation (Reference 2-6).

2.1.1.1 Operating Characteristics

Typical design and operating characteristics for utility boilers are given in Table 2-1. For one of these characteristics — throttle pressure — there is a recent trend away from supercritical back to subcritical. Less than 20 percent of the 1975 utility boiler orders specified supercritical pressures, compared with nearly 40 percent in 1971 (Reference 2-12). Throttle temperatures are remaining at about 840K (1,050F) due to material limitations.

Significant new trends in furnace design are just beginning to emerge in response to the recent emphasis on coal-fired units, particularly those capable of burning lower grade Western coals. Furnace volumes for coal firing — which have always been greater than those of furnaces designed to burn oil or gas — are expected to increase to a maximum of about 28,000 m^3 (1×10^6 ft^3), with average volumetric heat release decreasing to around 122 to 165 kJ/m^3s (12,000 to 16,000 Btu/ft^3 hr) for coal. The movement towards coal-fired units has also caused a marked decrease in the use of pressurized furnaces. More than 85 percent of the 1975 orders were for either balanced draft or slightly negative pressure furnaces, compared to less than 45 percent in 1971 (Reference 2-12).

2.1.1.2 Utility Boiler Combustion Process and Effluent Stream Characterization

Utility boilers have several multimedia effluent streams which may be affected by altering the combustion process to control NO_x formation. This section briefly discusses the combustion process in utility boilers and identifies the multimedia effluent streams emitting from these units. It also includes a listing of nonconventional operating practices which may affect the makeup of these effluent streams. The following discussion concentrates on coal since it is the main fuel now used in utility boilers, and it requires more process equipment than other fuels.

TABLE 2-1. DESIGN AND OPERATING CHARACTERISTICS OF UTILITY BOILERS (Reference 2-12)

Input capacity	73 MW to 3,800 MW (250 MBtu/hr to 13,000 MBtu/hr)
Steam pressure	~18.6 MPa (2,700 psi) subcritical ~26.2 MPa (3,800 psi) supercritical
Steam temperature	755 to 840K (900 to 1,050F)
Furnace volume	Up to 28,000 m^3 (1×10^6 ft^3)
Furnace pressure	(-50) to 1,000 Pa (-0.2 to 40 in. H_2O)
Furnace heat release	Coal, 104 to 250 kJ/m^3s (10,000 to 24,000 Btu/ft^3hr) Oil and gas, 208 to 518 kJ/m^3s (20,000 to 50,000 Btu/ft^3hr)
Excess air	25 percent coal 10 percent oil 8 percent gas

Types of processes in utility boilers include fuel combustion, flue gas cleaning, ash removal, and fireside boiler tube cleanup. Figure 2-4 gives a flow diagram for a typical pulverized coal-fueled boiler, showing how these four processes relate to each other.

The fuel combustion process in utility boilers produces bottom or hopper ash, combustion gases, volatilized noncombustible contaminants of the fuel, and suspended ash entrained in the hot flue gases. Coal usually contains between 5 and 15 percent ash and up to about 60 trace elements.* Residual fuel oils contain less than 0.2 percent ash, but may have significant amounts of trace metallics, particularly vanadium. Natural gas contains virtually no ash or trace element constituents.

Up to 65 percent of the ash in coal is entrained in the hot combustion gases and either deposited on various boiler parts or carried out of the boiler to the flyash collection system. Flue gas cleanup generally consists of particulate removal equipment (cyclone, electrostatic precipitator, or baghouse). Sulfur dioxide removal devices are employed on less than 5 percent of current installations. The flyash collection equipment usually produces a dry solid waste stream which is removed either in the dry state or by a wastewater sluicing stream which is diverted to an ash settling pond. A recent analysis of power plant data (Reference 2-10) shows that about 80 percent of utility boilers remove ash by sluice water, and the remaining 20 percent use dry removal.

The entrained ash deposited on furnace walls or other heat transfer sections may reduce heat transfer efficiency and lead to severe slagging or fouling if not removed. Soot blowing systems using steam or compressed air are used to maintain fireside tube surfaces on a regular schedule depending upon fuel and load. The soot blown off the boiler tubes becomes entrained in the flue gases or settles in the superheater or economizer ash hoppers.

Coal ash which is not entrained in combustion gases either falls dry to the furnace hopper (dry bottom) or melts and adheres to the furnace wall and flows into a slag tank (wet bottom). Dry ash is removed by way of a pneumatic conveyance system or by a wastewater sluicing stream to an ash settling pond. Superheater and economizer ash hoppers generally produce insignificant amounts of ash compared to the furnace hopper and the flyash collection system. Table 2-2 summarizes the effluent streams associated with the combustion process in utility boilers.

Several periodic or nonstandard operating procedures can affect the composition of the various effluent streams discussed above. Although sootblowing was described above because it is so commonly used, it is also included in the following periodic or nonstandard operations:

---

*Trace defined as <1 percent by weight of coal

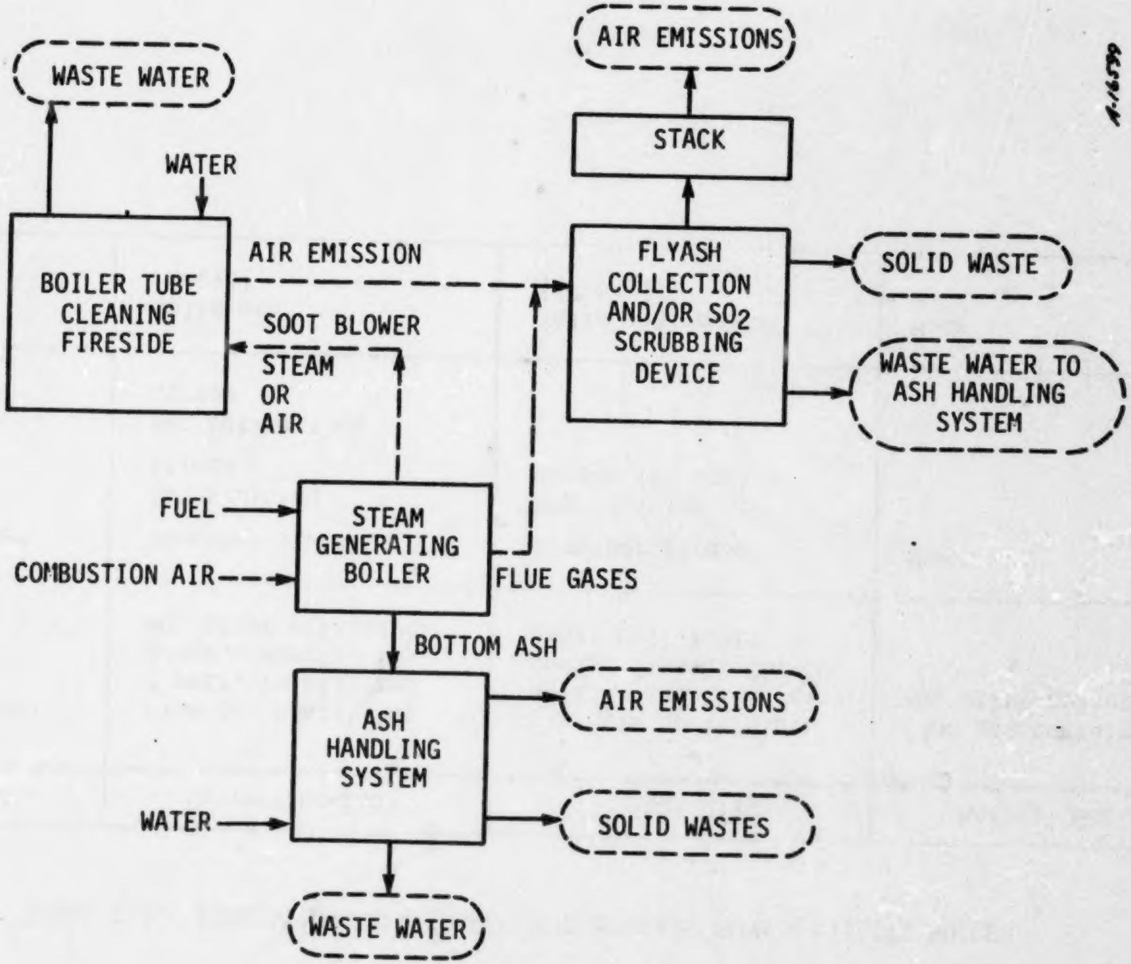

WASTE WATER
WATER
BOILER TUBE CLEANING FIRESIDE
AIR EMISSION
SOOT BLOWER
STEAM OR AIR
FUEL
COMBUSTION AIR
STEAM GENERATING BOILER
FLUE GASES
BOTTOM ASH
ASH HANDLING SYSTEM
WATER
WASTE WATER
AIR EMISSIONS
SOLID WASTES
AIR EMISSIONS
STACK
FLYASH COLLECTION AND/OR SO2 SCRUBBING DEVICE
SOLID WASTE
WASTE WATER TO ASH HANDLING SYSTEM
A-16599

Figure 2-4. Coal-fired utility boiler combustion process flow diagram.

TABLE 2-2. COMBUSTION RELATED EFFLUENT STREAMS FROM A UTILITY BOILER

Stream/Fuel	Pulverized Coal	Fuel Oil	Natural Gas
Gaseous effluent streams	Flue gas containing flyash, volatilized trace elements, SO_2, NO, other pollutants	Flue gas containing volatilized trace elements, flyash, NO, SO_2 other pollutants	Flue gas containing NO, other pollutants
Liquid effluent stream	Scrubber streams Ash sluicing stream Wet bottom slag stream	Scrubber stream Ash sluicing stream (if any)	None
Solid	Solid ash removal	Solid ash removal (if any)	None

- Sootblowing
- Startup or shutdown transients
- Load changes
- Fuel additives
- Rapping or vibrating
- Flameout
- Upsets
- Equipment failure

Table 2-3 shows how often these operations take place and the effluent streams which they may affect.

2.1.1.3 Utility and Large Industrial Boiler Equipment Categories

Figure 2-5 shows the important types of utility boiler equipment, based on current distribution, fuel consumption, and projected growth. Vertical and stoker units make up a relatively small fraction of the total, but are included for completeness. No differentiation is made between dry and wet bottom coal burning boilers of a specific design type. Since distillate oil and crude oil make up a very small portion of the total petroleum fuels, they have been included in residual oil totals in all cases.

These equipment type/fuel combinations will be carried through for quantification of emissions in Section 5.

2.1.2 Packaged Boilers

This equipment category is comprised of all industrial, commercial and residential packaged boilers. In general, they have an input capacity of less than 75 MW (250 MBtu/hr). Some packaged boilers have a larger capacity but they are small in number and are sufficiently close in design to units below 75 MW to be included in this category.

Packaged boilers are constructed in watertube, firetube, cast iron, and shell designs. Each of these designs has a fairly distinct capacity range. These units are fueled primarily by residual and distillate oil, natural gas, and stoker coal. In addition, liquid and solid waste fuels and process gases are sometimes used. In terms of installed units, packaged boilers far outnumber field-erected boilers. Packaged boilers, however, consume only about 91 percent as much fuel as field-erected

TABLE 2-3. EFFECT OF NONSTANDARD OPERATING PROCEDURES ON THE EFFLUENT STREAMS FROM A DRY BOTTOM PULVERIZED COAL-FIRED BOILER (Reference 2-18)

(● Indicates possible affect on stream composition)

Procedure	Frequency	Gaseous	Liquid	Solid
Soot blowing	3 to 4/day	●	●	●
Startup, shutdown	12 to 50/yr	●	●	
Load change	1/day	●	●	
Fuel additives	Continuous if used	●	●	●
Rapping, vibrating	3 to 4/day	●	●	●
Flameout	<1/yr	●		●
Upset	<1/yr	●		
Equipment failure	Several/yr	●	●	●

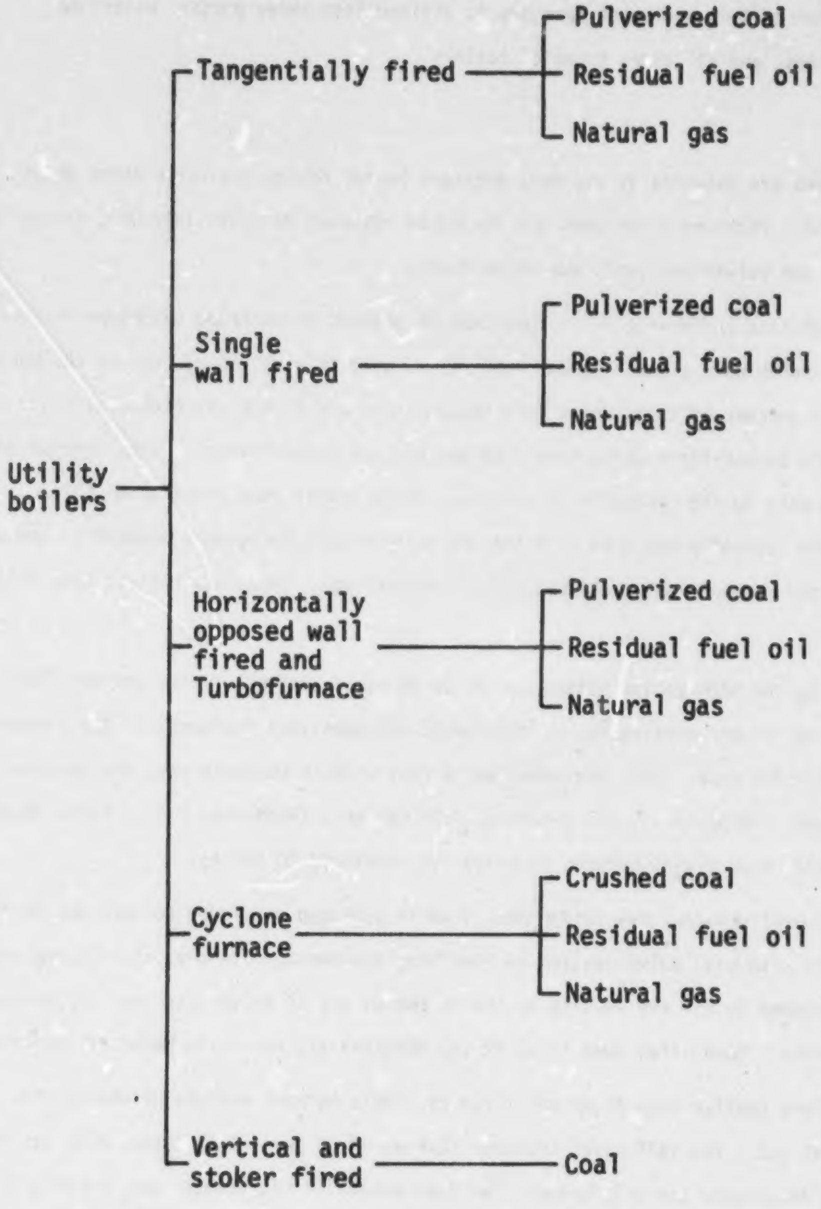

Utility boilers
Tangentially fired
Pulverized coal
Residual fuel oil
Natural gas
Single wall fired
Pulverized coal
Residual fuel oil
Natural gas
Horizontally opposed wall fired and Turbofurnace
Pulverized coal
Residual fuel oil
Natural gas
Cyclone furnace
Crushed coal
Residual fuel oil
Natural gas
Vertical and stoker fired
Coal

Figure 2-5. Utility boiler equipment categories.

boilers annually. Packaged boilers are primarily used for industrial process steam; commercial and residential heating; and hot water supply.

Due to the large capacity range of packaged boilers — and the large number of distinct designs — the discussion of this equipment category is divided into three parts: watertube boilers, firetube boilers, and all other types of boilers.

Watertube Boilers

Watertube boilers are essentially the only packaged boiler design available above about 9 MW (30 MBtu/hr) input. Packaged watertubes are fueled by residual or distillate oil, natural gas, process gases, stoker and pulverized coal, and waste fuels.

1975 sales statistics (Reference 2-19) show that 86 percent of packaged watertube boilers were burner-fired and 14 percent were stoker-fired. Fuel oil is used in about 50 percent of the burner-fired units. About 75 percent of these units fire residual oil and 25 percent fire distillate oil. About 40 percent of the burner-fired units have dual gas and oil capabilities. Units limited only to natural gas firing make up the remaining 10 percent. Units larger than about 30 MW GJ/hr (100 MBtu/hr) input are typically equipped with the one or more utility burners mounted in the wall firing configuration and commonly burn residual oil or natural gas. (Most new boilers have both capabilities.)

Steam is used as the atomization method for 70 to 80 percent of oil-fueled boilers (Reference 2-7). Mechanical or air atomization is also used, but much less frequently. Gas burners are usually of the register type. Coal and other solid fuel stokers commonly used are spreader (~50 percent), overfeed (~10 percent), and underfeed (~20 percent) (Reference 2-7). Pulverized, hand-fired, and miscellaneous firing methods comprise the remaining 20 percent.

In the past, pulverized coal has seldom been used in packaged watertube boilers due to the capital costs involved with coal pulverization and handling equipment. The availability and competitive cost of coal compared to oil are leading to the increased use of pulverized coal in the larger packaged watertube units. Capacities down to 20 MW (70 MBtu/hr) are now being marketed (Reference 2-12).

Watertube boilers smaller than 30 MW are fired by single burners and use primarily distillate oil or natural gas. The 1975 sales indicate that about 30 percent of these units are natural gas fueled and about 45 percent are oil fueled. Two fuel capabilities, natural gas and oil, exist in about 25 percent of the units. The most common atomization methods are mechanical pressure atomizing, which accounts for about 70 percent and air atomizing, which accounts for about 30 percent (Reference 2-19). Coal firing is available only in stoker units.

The smaller watertube boilers are mainly used for industrial process steam. Some commercial space heating is also done with these units, although they are somewhat large to be regularly used for this purpose (Reference 2-20).

Firetube Boilers

In firetube boilers, the products of combustion are directed from the combustion chamber through straight tubes which are submerged in water. Because of the sensitivity to fouling with this design, firetube boilers normally burn fuel oils and natural gas rather than high ash fuels like coal. Residual oil and natural gas are the main fuels for the larger firetube boilers, while natural gas and distillate oil predominate in the smaller units. Firing is by single burner. Rotary, mechanical, or air atomization are used for oil firing. Atmospheric burners are predominantly used for natural gas firing.

Scotch, firebox, and horizontal return tube (HRT) are the three main types of firetube units in the field at the present time. Recent sales indicate that the firebox unit has diminished in popularity over the past 5 years (Reference 2-21). Scotch firetubes, in which the burner flame is contained within an elongated combustion chamber surrounded by water, are the most popular with efficiencies of 80 percent. The rear wall of the furnace in scotch firetubes is either water-lined (wet-back) or refractory-lined (dry-back). Firebox units are constructed with internal, steel encased, water-jacketed fireboxes which produce good circulation and efficiencies of 80 percent. HRT boilers have the advantage of low cost, but their efficiency seldom exceeds 70 percent (Reference 2-22). Brickset (external) or internal furnaces are available for HRT units. Firetube boilers are used for commercial and domestic space heating; larger units are also used for industrial process steam.

Other Packaged Boilers

Cast iron boilers are available with input capacities up to 4 MW (13.5 MBtu/hr) and operate almost exclusively on distillate oil and natural gas fuels. These boilers are designed to supply low pressure steam or hot water and are used primarily for air or water heating systems. The primary advantage to cast iron boilers for heating is that they require a very low level of maintenance and have a high reliability and lifetime. On the other hand, their cost is typically higher than the cost of a comparable firetube boiler.

Other packaged boilers include several which are used for residential and commercial heating or hot water, including shell boilers and residential steam and hot water units. This group also includes several designs which are obsolete or insignificant on a national scale. Included among these are compact, locomotive, short-firebox, and vertical firetube designs, and straight tube, anthracite, and bituminous coal research watertube designs. Because of the importance of the package boiler sector, these designs will be dealt with under the single category — steam and hot water units.

2.1.2.1 Operating Characteristics

Typical operating characteristics for natural gas- and residential oil-fueled watertube boilers, a small watertube boiler, a cast iron boiler and a scotch firetube boiler are presented in Table 2-4.

2.1.2.2 Effluent Stream Characterization

Flue gases are usually the only combustion-related effluent stream originating from packaged boilers. In the case where pulverized or stoker coal, solid wastes, or other high ash fuels are burned, both liquid and solid effluent streams may be produced if ash collection and flue gas cleanup systems are used. Table 2-5 lists the effluent streams associated with each of these fuels.

2.1.2.3 Packaged Boiler Equipment Categories

Figure 2-6 shows the significant types of packaged boilers and the fuels burned in each type. The selection was based on distribution, similarities in equipment design, and projected growth. Gaseous fuels include process, natural and tank gases. Stoker units are typically underfeed in this capacity range. Oil fuels include distillates and residuals.

2.1.3 Warm Air Furnaces and Other Commercial and Residential Combustion Equipment

This category is made up of residential and commercial warm air furnaces used for comfort heating, plus miscellaneous commercial and residential appliances used in cooking, refrigeration, air conditioning, clothes drying, etc. Figure 2-7 gives an overview of the equipment types. The letters on the right-hand side of the figure indicate which fuels are used in each kind of unit.

There are two basic types of commercial and residential warm air furnaces: space heaters, where the unit is located in the room or area it heats; and central heaters, which use ducts to transport and discharge warm air into the heated space.

Space Heaters

Space heaters are room heaters, floor furnaces, wall furnaces which discharge heated air directly into the space to be heated, and central heaters. Central heaters are the largest majority of warm air furnaces and are discussed separately in the following subsection. The capacity of room

TABLE 2-4. TYPICAL DESIGN AND OPERATING CHARACTERISTICS OF PACKAGED BOILERS

	(Reference 2-23)	(Reference 2-23)	(Reference 2-23)	(Reference 2-20)	(Reference 2-20)
Design	Watertube	Watertube	Watertube	Scotch firetube	Cast iron
Fuel	Natural gas	Residual fuel oil	Natural gas	Residual fuel oil	Distillate fuel oil
Input capacity MW (MBtu/hr)	44 (150)	38 (130)	8.5 (29)	2.9 (10)	0.38 (1.3)
Furnace volume m^3 (ft^3)	154 (5,450)	123 (4,340)	21.4 (755)	2.5 (87)	0.57 (20)
Heat release kJ/m^3s ($MBtu/ft^3$ hr)	285 (0.0275)	310 (0.030)	397 (0.0384)	1,190 (0.114)	673 (0.065)
Operating pressure kPa (psig)	NA	NA	NA	1,030 (150)	103 (15)
Burner type (number)	Ring (1)	Steam atomization (2)	Ring (1)	Air atomizing (2)	Pressure atomizing (1)
Fuel preheat K (F)	None	392 (210)	None	371 (208)	None
Stack temperature K (F)	422 (300)	422 (300)	567 (560)	NA	NA
Excess oxygen %	5	7.1	0.9	4.9	4.4

T-184

TABLE 2-5. PACKAGED BOILER EFFLUENT STREAMS

	Pulverized Coal	Stoker Coal	Fuel Oil	Natural Gas
Gaseous streams	Flue gas containing flyash, volatilized trace elements, SO_2, NO_x, other pollutants	Flue gas containing flyash, volatilized trace elements, SO_2, NO_x, other pollutants	Flue gas containing flyash, volatilized trace elements, SO_2, NO_x, other pollutants	Flue gas containing NO, other pollutants
Liquid stream	Ash sluicing water, wet scrubber stream	Ash sluicing water, wet scrubber stream	None	None
Solid stream	Solid ash removal	Solid ash removal	Solid ash removal (if any)	None

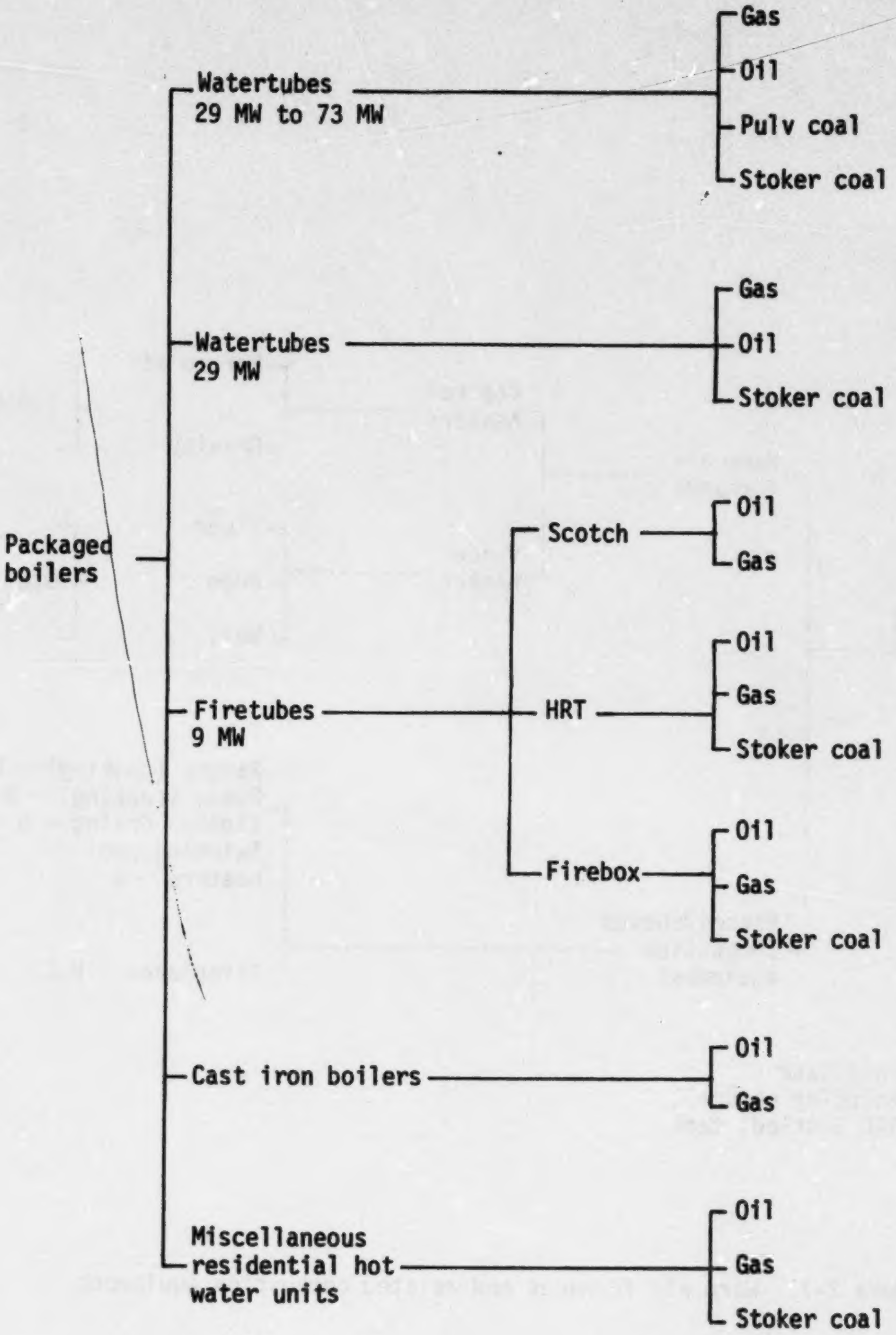

Packaged boilers
Watertubes 29 MW to 73 MW
Gas
Oil
Pulv coal
Stoker coal
Watertubes 29 MW
Gas
Oil
Stoker coal
Firetubes 9 MW
Scotch
Oil
Gas
HRT
Oil
Gas
Stoker coal
Firebox
Oil
Gas
Stoker coal
Cast iron boilers
Oil
Gas
Miscellaneous residential hot water units
Oil
Gas
Stoker coal

Figure 2-6. Packaged boiler equipment categories.

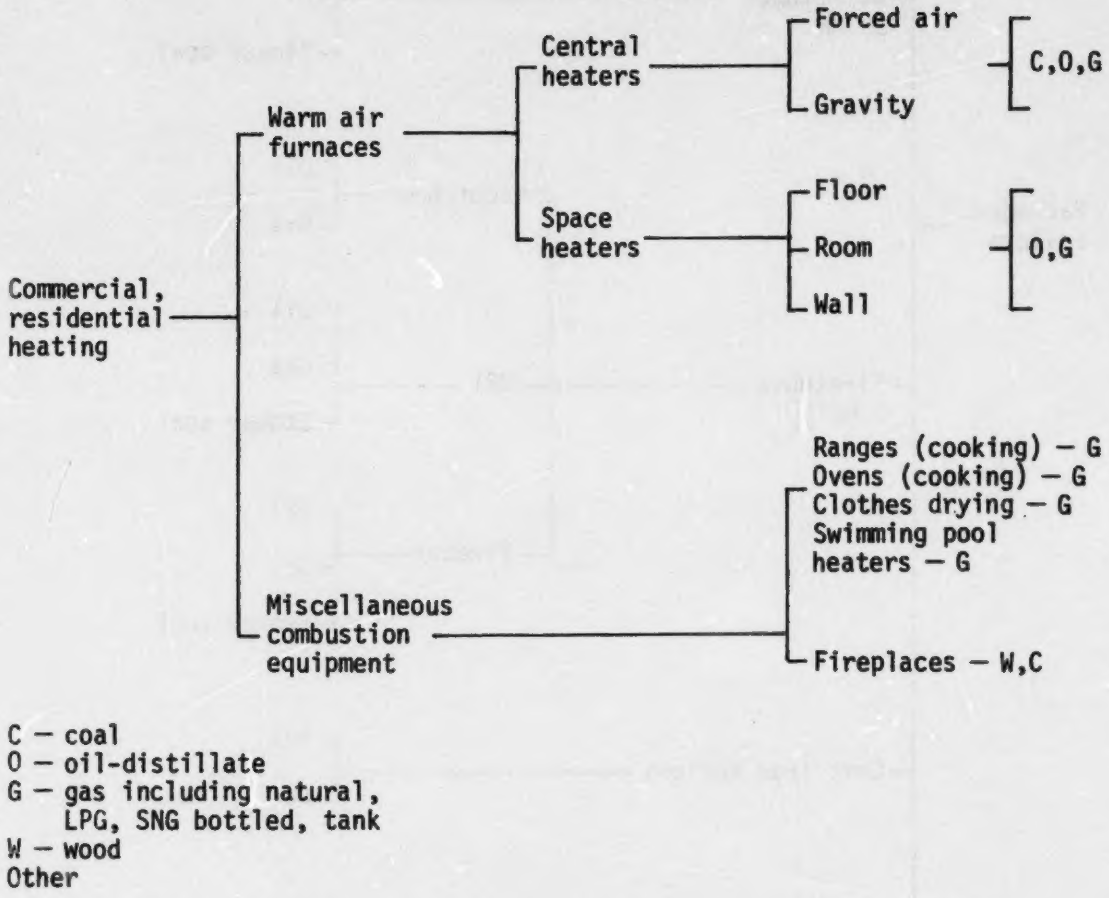

Commercial, residential heating
Warm air furnaces
Central heaters
Forced air
Gravity
C,O,G
Space heaters
Floor
Room
Wall
O,G
Miscellaneous combustion equipment
Ranges (cooking) — G
Ovens (cooking) — G
Clothes drying — G
Swimming pool heaters — G
Fireplaces — W,C
C — coal
O — oil-distillate
G — gas including natural, LPG, SNG bottled, tank
W — wood
Other

Figure 2-7. Warm air furnaces and related combustion equipment.

heaters, floor furnaces, and wall furnaces seldom exceeds 108 MJ/hr (100,000 Btu/hr). The 1970 Census shows that less than 9 percent of the nation's heating is done by space heaters and that more than 98 percent of these are either gas- or oil-fired (55 percent by natural gas, 43 percent by distillate fuel oil).

Room heaters are self-contained, free-standing units which are equipped with a flue if fueled by oil; floor- and wall-mounted furnaces are always vented to the atmosphere. These units heat by either radiation or natural or forced air circulation. Because of the large variety of manufacturers and the uncertainty as to the age, location, and condition of space heaters, the design and operating characteristics of these heaters are difficult to quantify. As a result, implementation of NO_x controls for these units is unlikely. Because of their relative unimportance for this study, all space heaters will be subsequently treated as a single equipment type.

Central Heaters

The large majority of warm air furnaces (about 60 percent of new units) (Reference 2-24) are forced-air central furnaces with capacities up to about 88 kW (~300,000 Btu/hr). These heaters are operated either by gravity or by a pressure blower (forced-air system) for air discharge and return. Central gravity-operated furnaces rarely exceed 44 kW (150,000 Btu/hr). The furnace in these central heaters is enclosed in a rectangular steel casing, and fuel is burned in the primary combustion space of a metal-walled heat exchanger. Heat exchangers in these warm-air furnaces have a single combustion chamber, which is usually cylindrical or divided into a series of individual sections. Cylindrical combustion chambers are normally used with a single-port, oil-fired burner; and the sectional type is used with multiple gas-fired burners. Combustion products pass through secondary flue gas passages of the heat exchanger and exit through a flue to the atmosphere.

Central warm air furnaces are usually classified into four types:

- Downflow, in which the blower is mounted above the heat exchanger, the flue gas discharges at the side or top, and the warm air discharges at the side
- Upflow or "high boy", in which the blower is mounted below the heat exchanger and the warm air and the flue gas discharge from the top of the unit
- Horizontal, in which the blower is mounted adjacent to the heat exchanger, the flue gas discharges from the side, and warm air exits at the end of the unit
- Basement or "low boy", similar to the horizontal, except that the flue gas discharges at the end of the unit and the warm air exits at the top

The main difference between these four types of furnaces is how the blower and the heat exchanger are located in relationship to each other. Since there are only minimal differences in the burner and combustion chamber design for the above types and natural circulation units, they will be dealt with as a single equipment type for subsequent emissions inventories.

According to U.S. Census statistics for 1970, over 55 percent of the nation's heating units were warm air furnaces. About 67 percent of these units burned natural gas, while distillate fuel oil was fired in 23 percent. Coal, wood and various bottled, tank, or LP gas accounted for the remaining 10 percent of fuel used. Although there has been a continuing trend in the recent past toward commercial and residential warm air furnaces which use natural gas, the percentage of equipment in the entire residential and commercial sector fueled by natural gas is expected to drop from 37 percent in 1974 to 35 percent by 1985, and to decline further to 32 percent by 2000 (Reference 2-25). Moreover, the use of fossil fuels of all types in this sector is expected to drop from 79 percent in 1974 to 57 percent in 2000. On a national scale, the most important fuels for warm air furnaces are still natural gas and distillate oils. Other fuels will not be considered except coal, which is still used for space and central heating in some areas and could present localized pollution problems.

Miscellaneous Combustion Equipment

Other commercial and residential combustion equipment in this sector includes ranges and ovens, clothes dryers, fireplaces, swimming pool heaters, and refrigeration and air conditioning equipment. Gas was used for about half of all cooking in 1973, and electricity for the remaining half. Although there were more than 40 million clothes dryers in 1974 (Reference 2-26), no data are available as to how many were fueled by gas. Refrigeration and air conditioning are typically electrical vapor compression units. A few absorption units fired with natural or bottled gas are used in domestic application.

The emissions from domestic cooking are small compared to warm air furnaces. They are mostly of concern for the part they play in indoor air pollution rather than for their contribution to AQCR or national NO_x loadings. Low-NO_x burners for domestic gas combustion are presently being developed by the gas industry (Reference 2-27). Efforts to characterize indoor air pollution and develop low pollution burners will be monitored throughout the NO_x E/A, but these efforts will receive secondary emphasis in the process engineering and environmental assessment studies. These miscellaneous domestic combustion sources will subsequently be dealt with as a single category.

2.1.3.1 Operating Characteristics

Operating characteristics will be given only for central warm air furnaces, since typical characteristics of space heaters and miscellaneous combustion equipment in this sector are difficult to generalize.

One of the most important operational characteristics of all comfort heating devices is their cyclic operating mode. Typical residential warm air heaters have about two to five cycles per hour, with a 30 to 50 percent on-time (Reference 2-20). This cyclic operation is important to this program for two reasons. First, the emissions from furnaces during startup and shutdown may be substantially higher than during continuous operation and may also be affected by the application of NO_x controls. Second, the thermal efficiency of these furnaces is substantially lowered by heat losses to the flue during downtime, offsetting any gains in efficiency which may come from low-NO_x, high-efficiency burners.

The gas burners on warm air furnaces are naturally aspirated types made up of three to four venturis, with distribution pipes consisting of rows of small orifices. The primary air is drawn into the venturi by the gas pressure and premixes with the gas before igniting. The primary air/fuel ratio can be controlled by small shutters at the end of each venturi. Secondary air from the furnace room enters around the burners to reduce the overall flame temperature and allow complete combustion. These units are also equipped with draft diverters to dilute the flue gas stream and prevent downdrafts from blowing out the pilot.

Typical operating conditions of a 29 kW (100,000 Btu/hr) residential gas-fired warm air furnace are given in Table 2-6.

Oil-fired forced air furnaces are now being made with overall volumes not much greater than gas-fired versions. There are considerable differences between the two types of units in internal operation, however. In an oil-fired central heater, the heat is supplied by a gun-type oil burner made up of a combustion air blower, motor, damper, fuel pump, spark ignition system, main air tube and swirlers, and fuel nozzle. The flow rate of the fuel is determined by the oil nozzle orifice size, and the total air flow rate by the blower and damper. The proper air/fuel ratio is adjusted with the damper until the optimum CO and smoke levels are achieved. The burner is mounted in a refractory or refractory-felt-lined combustion chamber which is cooled by air circulating through the housing. From the combustion chamber, the flue gas passes through a heat exchanger and then out the stack. The absence of a pilot flame and the use of a forced draft system make a draft diverter in the flue unnecessary. The burner blower may supply the full pressure to exhaust the gas from the stack, or it may rely partially on the buoyancy forces downstream of the stack. Table 2-7 lists typical operating conditions for an oil-fired home heating furnace.

TABLE 2-6. DESIGN AND OPERATING CHARACTERISTICS OF A TYPICAL 29 KW GAS-FIRED FORCED AIR FURNACE

Heat exchanger area:	2.8 to 3.3 m^2 (30 to 35 ft^2)
Draft system:	Natural
Excess combustion air:	20 to 50 percent
Overall heat transfer coefficient kW/(m^2K)	11.3 to 17 (2 to 3 Btu/hr-ft^2F)
Combustion chamber pressure	±49.8 Pa (±0.2 in. H_2O)
Exit flue gas temperature: (Before flue gas diverter)	506 to 617K (450 to 650F)
Overall steady state efficiency	75 to 80 percent
Common operating mode:	On/off

TABLE 2-7. DESIGN AND OPERATING CHARACTERISTICS OF A TYPICAL 29 KW OIL-FIRED FORCED AIR FURNACE

Heat exchanger area:	1.9 to 2.8 m^2 (20 to 30 ft^2)
Draft system:	Forced
Excess combustion air:	20 to 100 percent
Overall heat transfer coefficient:	11.3 to 17 W/(m^2K) (2 to 3 Btu/ft^2hr F)
Combustion chamber pressure:	12.45 Pa to 49.8 Pa (0.05 to 0.2 in. H_2O)
Exit flue gas temperature:	533 to 756K (500 to 900F)
Overall steady state efficiency	70 to 80 percent
Operation mode:	On/off

2.1.3.2 Effluent Stream Characterization

Flue gases are generally the only combustion-related effluent from these equipment types. In the rare case of a solid-fueled warm air furnace, a solid waste stream consisting of dry ash would result. The composition of the flue gas depends on the kind of fuel used and its combustion characteristics, which are determined in part by the design and controls employed in the unit. Another important factor in flue gas composition is the cyclic nature of normal warm air furnace operation.

Periodic operating practices for this equipment sector include unit servicing (especially burner tuning or replacement), and unit cleaning. While these practices can increase thermal efficiency, they do not usually help reduce NO_x emissions.

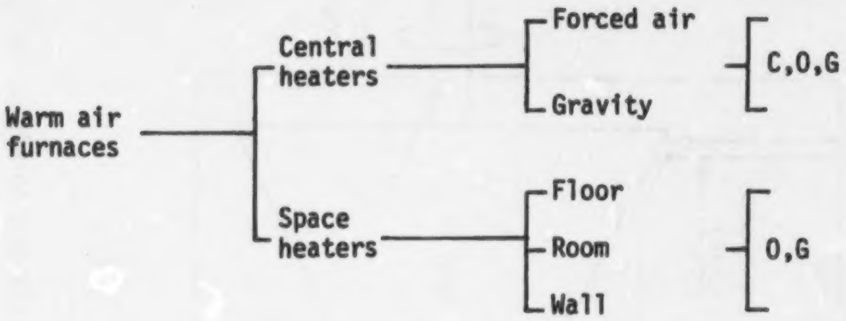
2.1.3.3 Warm Air Furnace Equipment Categories

Figure 2-8 shows the equipment in this sector which will be treated in subsequent sections as potentially important sources of NO_x emissions. These types of equipment have been selected on the basis of distribution, potential growth, fuel burned, and the potential for applying NO_x control.

2.1.4 Gas Turbines

Gas turbines are rotary internal combustion engines fueled by natural gas, diesel or distillate fuel oils, and occasionally residual or crude oils. These units range in capacity from 30 kW (40 hp) to over 75 MW (100,000 hp) power output and may be installed in groups for larger power output. As shown in Figure 2-9, the basic gas turbine consists of a compressor, combustion chambers, and a turbine. The compressor delivers pressurized combustion air to the combustors at compression ratios of up to 20 to 1. Injectors introduce fuel into the combustors and the mixture is burned with exit temperatures up to 1,370K (2,000F) before quenching. The hot combustion gases are rapidly quenched by secondary dilution air and then expanded through the turbine which drives the compressor and provides shaft power. In some applications, exhaust gases are also expanded through a power turbine.

While simple-cycle gas turbines have only the three components described above, regenerative-cycle gas turbines also use hot exhaust gases (700K to 870K, 800F to 1,100F) to preheat the inlet air between the compressor and the combustor. This makes it possible to recover some of the thermal energy in the exhaust gases and to increase thermal efficiency. A third type of turbine is the combined-cycle gas turbine. This is basically a simple-cycle unit which exhausts to a waste heat boiler to recover thermal energy from the exhaust gases. In some cases, this waste heat boiler is also designed to burn additional fuels to supplement steam production, a process which is referred to as supplementary firing.


Warm air furnaces
Central heaters
Space heaters
Forced air
Gravity
Floor
Room
Wall
C,O,G
O,G

C — Coal

O — Oil, distillate

G — Gas, including natural, LPG, SNG bottled, tank

Figure 2-8. Important commercial and residential combustion equipment.

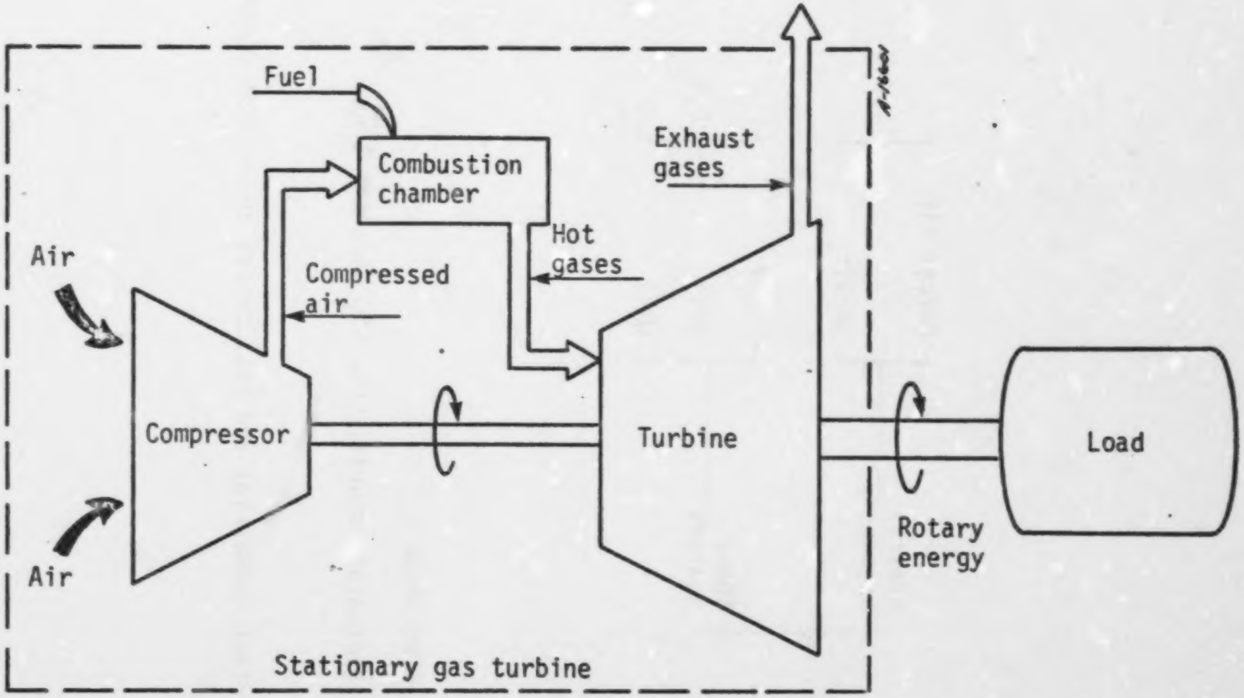

Fuel
Combustion chamber
Exhaust gases
Hot gases
Air
Compressed air
Compressor
Turbine
Load
Rotary energy
Air
Stationary gas turbine

Figure 2-9. Basic simple cycle gas turbine.

On some gas turbine units the combustor is placed axially between the compressor and the turbine. In this design, the combustor may be made up of a series of individual "cans" encircling the drive shaft or of two concentric cylinders mounted so as to produce a single annular combustion chamber (hence the terms canannular or annular combustor designs). These units are generally an outgrowth of aircraft turbine design technology, and are often referred to as aircraft derivative turbines. On other gas turbines, the combustor is a single large volume, which is connected to the compressor and turbine by ducting, but which is not necessarily physically located between the compressor and the turbine. This design is obviously strictly for stationary or industrial applications and is referred to as such.

Gas turbines have been extremely popular in the past decade because of the relatively short construction lead times; low cost; ease and speed of installation; low physical profile (low buildings, short stacks, little visible emissions, quiet operation). In addition, features like remote operation, low maintenance, high power-to-weight ratio, and short startup time have added to their popularity. Primary applications of gas turbines include electrical generation (peaking and base-load), pumping, gas compression, standby electricity generation, and miscellaneous industrial uses. By far the largest use of gas turbines is for peaking power (>2,000 hrs/yr).

Stationary gas turbines are typically divided into three capacity ranges:

- Large capacity, including multiple and combined cycle >15 MW (20,000 hp) output
- Medium capacity 4 MW to 15 MW (5,000 to 20,000 hp) output
- Small capacity <4 MW (5,000 hp) output

Large-Capacity Gas Turbines

Large-capacity gas turbines range up to 100 MW (134,000 hp) power output, while combined-cycle and multiple turbines range up to 1,230 MW. These equipment types are used almost exclusively by electric utilities. Since equipment of this size does not lend itself to large-scale production runs, lead times of 6 to 24 months for these units are not uncommon. The majority of installed gas turbines are simple cycle units, and the industrial types are slightly more common than aircraft-derived turbines.

Simple- and combined-cycle turbines offer the greatest possibilities for NO_x control with dry combustion controls, especially since the high turbine inlet temperature of regenerative-cycle turbines has decreased their popularity. Similarly, industrial gas turbines have much more potential for combustor redesign than do the compact, physically-restricted, aircraft derivative units.

Although gas turbines presently account for about 8 percent of installed electrical generating capacity, they actually generate less than 2 percent (Reference 2-28). Over 90 percent of gas turbine capacity sold in the U.S. now goes to electrical utilities, and this percentage is continuing to increase. Shipments of gas turbines in 1975 were down considerably (~65 percent) over preceding years, but the gas turbine fraction of total electrical generating equipment shipments declined only 7 percent (Reference 2-29).

Recent trends in large gas turbines have been towards higher capacities and improved heat rates. For the future, a recent survey of users (Reference 2-30) indicates that combined-cycle turbines are the preferred design for intermediate or base load applications because of their improved heat rate and fuel flexibility. Simple-cycle turbines are preferred for peaking. In the same survey, users predicted that gas turbines will continue to contribute about 10 percent of the total electrical generating capacity through at least 1985. Because of this projected growth, large gas turbines will subsequently be studied as a distinct equipment type.

Medium-Capacity Gas Turbines

Medium-capacity gas turbines are used primarily for electrical standby generation, pipeline compression and pumping, and industrial electricity generation — although they also have a wide variety of other applications. Most turbines of this capacity are simple-cycle units; only a small fraction are regenerative-cycle, and there are essentially no combined-cycle, medium-capacity turbines. Combustion modification on these units has been strongly directed toward the development of dry combustor controls, but the only commercially-available control methods are water or steam injection.

Because of the trend in utilities toward larger units and the movement in the oil and gas industry toward smaller capacities, fewer medium-capacity gas turbines are now sold per year than either of the other two sizes. In the oil and gas industry, units in this medium-capacity range operate about 8,000 hours per year; standby electric generation units may not exceed 200 hours per year. Units used for private industrial electricity generation, the third major application of this equipment, operate nearly full time. Because of their relatively large population, high application, and a fairly distinct distribution, medium-capacity gas turbines will subsequently be treated as a distinct equipment type.

Small-Capacity Gas Turbines

Small-capacity gas turbines are used by both the gas and oil industry and for standby electricity generation. These units represent less than 5 percent of the total installed gas turbine capacity in the U.S. All small-capacity turbines are simple-cycle designs, since regenerative- or combined-cycle turbines are not economical for these applications. Since the concentration of these units in gas and oil plants and in power plants for emergency electricity generation could present localized problems of NO_x, these units will be grouped into a single equipment type within the gas turbine sector.

2.1.4.1 Operating Characteristics

Although operating characteristics vary within each capacity range, it is still possible to present typical data for representative equipment. Table 2-8 gives design and operating characteristics for two large-capacity utility gas turbines fired with distillate oil fuel. Note the specific fuel consumption gained by the combined-cycle unit. Table 2-9 presents operating data for typical small- and medium-capacity gas turbines. The medium-capacity columns compare simple- and regenerative-cycle turbines, and clearly show the advantages in specific fuel consumption of the regenerative cycle.

Stationary gas turbines are normally operated at constant speed and output. Nonstandard operating practices for these units include startup and shutdown transients, load following, speed or power variation, servicing, and upsets such as fuel system failure, turbine or compressor breakage, or downstream equipment failure. Startup and shutdown transients are especially important in the large utility units used for peaking purposes which are operated daily for only short periods of time.

2.1.4.2 Effluent Stream Characterization

Exhaust gases are the only combustion-related effluent stream from gas turbines. The composition of this stream depends on the fuel being burned and on the general design and combustion characteristics of the unit. Nonstandard operating practices also affect the stream composition, generally reducing combustion efficiency and increasing unburned hydrocarbons or carbon monoxide.

2.1.4.3 Important Equipment Types

Figure 2-10 shows the important types of gas turbines and fuels which will be carried through to Section 5 for emission characterization and into the subsequent Task B1 emission projections. These types of equipment have been selected on the bases of present distribution, projected growth, and operating characteristics.

TABLE 2-8. OPERATING CHARACTERISTICS OF A TYPICAL ELECTRICAL UTILITY GAS TURBINE AND A COMBINED CYCLE UNIT (OIL FUEL)

	Utility GT	Combined Cycle Plant
Cycle type	S	Combined
Output capacity rating, MW	92.3	364.5 (4 turbines)
Specific fuel consumption MJ/kW-hr (Btu/kW-hr)	11.67 (11,058)	8.56 (8,114)
Compression ratio	10:1	10:1
Exhaust flow kg/s (lb/s)	345 (760)	256 (1 turbine) (563)
Exhaust temp K (F)	822 (1,020)	811 (1,000)

TABLE 2-9.[a] TYPICAL OPERATING CHARACTERISTICS OF A SIMPLE CYCLE AND A REGENERATIVE CYCLE MEDIUM CAPACITY AND A SIMPLE CYCLE SMALL CAPACITY GAS TURBINE

	Medium Capacity		Small capacity
Cycle type	Simple	Regenerative	Simple
Fuel	Distillate fuel oil	Distillate fuel oil	Distillate fuel oil
Output capacity MW	10.9 (14,600)	10.3 (13,750)	4.2 (5,660)
Compression ratio	~8:1	~8:1	4.6:1
Exhaust flow kg/s (lb/s)	52 (114)	52 (114)	35 (77.4)
Exhaust temp K (F)	806 (990)	817 (1,010)	742 (875)

[a] Reference 2-31

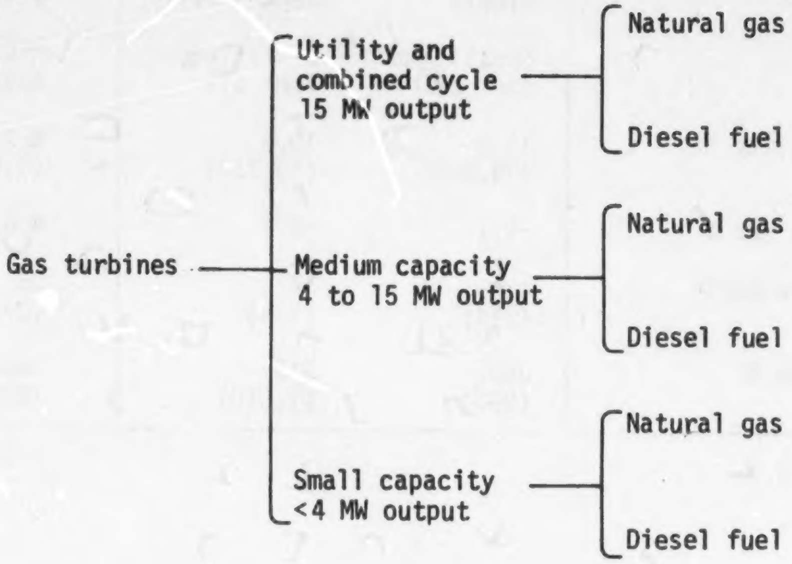

Gas turbines
Utility and combined cycle 15 MW output
Natural gas
Diesel fuel
Medium capacity 4 to 15 MW output
Natural gas
Diesel fuel
Small capacity <4 MW output
Natural gas
Diesel fuel

Figure 2-10. Important gas turbine equipment types and their fuels.

2.1.5 Stationary Reciprocating IC Engines

Reciprocating IC engines for stationary applications range in capacity from 750 W (1 hp) to 37 MW (50,000 hp). These engines are either compression ignition (CI) units fueled by diesel oil or a combination of natural gas and diesel oil (dual), or spark ignition (SI) units fueled by natural gas or gasoline.

Stationary reciprocating IC engines use two methods to ignite the fuel-air mixture in the combustion chamber. In CI engines, air is first compression-heated in the cylinder, and then diesel fuel is injected into the hot air where ignition is spontaneous. In SI engines, combustion is spark-initiated, with the natural gas or gasoline introduced either by injection or premixed with the combustion air in a carburetted system. Either 2- or 4-stroke power cycle designs with various combinations of fuel charging, air charging, and chamber design are available.

Reciprocating IC engines come in a wide range of sizes, are portable, can provide transient power, and are both cost and energy efficient in the medium size ranges. Therefore, they are frequently located in or adjacent to urban centers where power demands are greatest and pollution problems most acute. These units are used in a variety of applications because of their relatively short construction and installation time and the fact that they can be operated remotely. Applications range from shaft power for large electrical generators to small air compressors and welders.

As a whole, 73 percent of installed IC engine capacity is fueled by natural gas, 16 percent by diesel oil and 11 percent by gasoline. In terms of installed capacity, the oil and gas industry is the leading user of stationary IC engines for pipeline and production applications, followed by general industrial users, electric power generation, and agriculture. In terms of annual energy production, oil and gas industry applications again come first, followed by general industrial and electrical generation applications.

Because of the large variety of designs for stationary IC engines, they are typically divided into four major subgroups based on capacity:

- Large bore, high power: >75 kW/cyl (>100 hp/cyl)
- Medium power: 75 kW to 75 kW/cyl (100 hp to 100 hp/cyl), >1,000 rpm
- Small: 15 kW to 75 kW (20 hp to 100 hp)
- Very small: <15 kW (<20 hp)

Large Bore IC Engines

Large bore IC engines are typically high-power, low or medium speed, 4-stroke CI units fueled by diesel oil or dual fuel or 2- or 4-stroke SI units operating on natural gas. Dual-fueled engines and natural-gas-fueled spark ignition units account for 93 percent of all the fuel consumed by these large capacity engines. The majority of these engines are used for compressors for the oil and gas industry. These units have high average capacities, high load factor, and are operated continuously to produce large amounts of energy. Units used for electrical generation have large capacity, but are far fewer in number than engines used in the oil and gas industry. Major manufacturers of large bore IC engines estimate a 5 to 10 percent annual growth of sales for these units, primarily for standby, emergency electrical generation, and natural gas pipeline pumping.

Medium Power IC Engines

The primary manufacturers of medium power units are also the major manufacturers of similar capacity units for trucks, tractors, and construction equipment. As a result, medium power stationary engines tend to be modified mobile engines with rotative speeds in excess of 1,000 rpm. Engines in this capacity range usually burn either diesel or gasoline rather than natural gas. Major applications are in construction, agriculture, and industry for shaft power, pumping, and compressing. About 50 percent of the fuel consumed by these units is diesel oil, 33 percent gasoline, and the remainder natural gas. Growth of sales for this size range continues at about 3 to 5 percent per year.

Small IC Engines

Small IC engines are mainly one- or two-cylinder units fueled by gasoline and occasionally diesel oil. Primary applications for this equipment are generator sets, refrigeration compressors for trucks and railcars, small pumps, and off-the-road vehicles.

Very Small IC Engines

Although there are more very small IC engines than units of any other capacity range, they consume very little energy on a national scale because of their extremely low annual use rate (~50 hrs/year) and small size. Most engines in this category are single-cylinder, gasoline-fueled units used primarily for lawn and garden equipment and chainsaws. Accurate quantification of this equipment group is difficult due to the large number of sales, the extremely large population, low energy consumption, and the difficulty of determining the annual use rate. On both a national and local scale, this grouping is insignificant in terms of total NO_x emissions due to their low total fuel consumption.

2.1.5.1 Operating Characteristics

General operating conditions for IC engines for the four groups within this sector are impossible to quantify because of the large number of possible equipment designs and choices of fuel which affect the operation of an engine. Several of the design features and operational adjustments which may influence combustion-related pollutant formation are listed in Table 2-10.

2.1.5.2 Effluent Stream Characterization

Exhaust gas is the only effluent stream from IC engines under normal conditions. However, oil and cooling water that are replaced during maintenance need to be disposed of properly. Large stationary IC engines usually operate at constant load and speed. Nonstandard operating conditions include load change, startup and shutdown transients, and upsets such as fuel or electrical system failure.

2.1.5.3 IC Engine Equipment Categories

The absence of adequate data on any but the simplest equipment division requires the use of equipment groupings defined above. Figure 2-11 indicates the equipment type breakdown which will be used for subsequent quantification in Section 5.

2.1.6 Industrial Process Heating

Significant quantities of fuel are consumed by industrial process heating equipment in a wide variety of industries, including iron and steel production, glass manufacture, petroleum refining, cement manufacture, sulfuric acid manufacture, and brick and ceramics manufacture. In addition, there are dozens of industrial processes that burn smaller amounts of fuel, such as coffee roasting, drum cleaning, paint curing ovens, and smelting of metal ores, to name only a few.

2.1.6.1 Process Descriptions and Operating Conditions

Process descriptions are given below for those industries which use significant amounts of process heat.

2.1.6.1.1 Iron and Steel Industry

The iron and steel industry is one of the major contributors to combustion-related process NO_x emissions. The most important combustion processes are sinter lines, coke ovens, open hearth furnaces, soaking pits and reheat furnaces. The remaining combustion-related processes (pelletizing,

TABLE 2-10. DESIGN AND OPERATIONAL ADJUSTMENTS WHICH AFFECT EMISSIONS FOR IC ENGINES (Reference 2-32)

Design	Operational Adjustment
Surface to volume ratio	Air-to-fuel ratio
Bore and stroke	Torque (mean effective pressure)
Valve overlap	Speed
Displacement/cylinder	Spark timing
Strokes/power cycle	Fuel injection timing
Chamber design	Fuel properties
Compression ratio	Lubrication and maintenance
Air charging:	
Naturally aspirated	
Blower scavenged	
Turbocharged	
Fuel charging:	
Direct injection	
Indirect injection	
Carburetted	
Engine cooling	

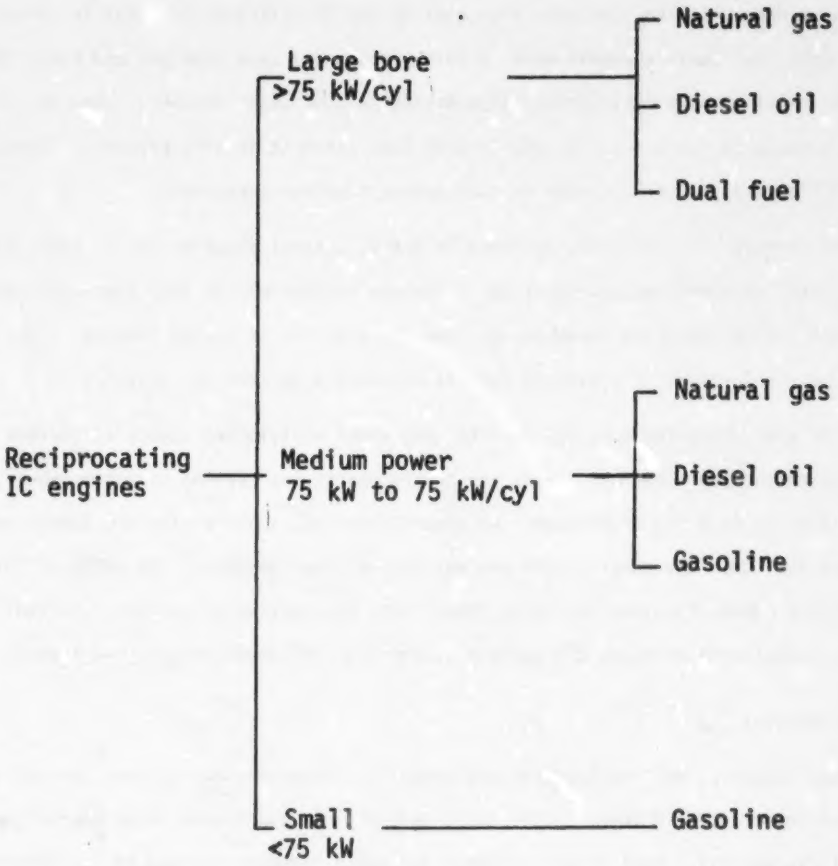

Reciprocating IC engines
Large bore >75 kW/cyl
Natural gas
Diesel oil
Dual fuel
Medium power 75 kW to 75 kW/cyl
Natural gas
Diesel oil
Gasoline
Small <75 kW
Gasoline

Figure 2-11. Important reciprocating IC engine equipment types and their fuels.

heat treating, and finishing) are less important because they use relatively small amounts of fuel (Reference 2-33).

Sintering machines are used to agglomerate ore fines, flue dust, and coke breeze for charging of a blast furnace. The use of this operation is presently declining at the rate of about 3.4 percent annually because of its inability to accomodate rolling mill scale which is contaminated with rolling oil.

Coke ovens produce metallurgical coke from coal by the distillation of volatile matter producing coke oven gas. The fuels commonly used in this process are coke oven gas and blast furnace gas. Although NO_x emissions are minimized by slow mixing in combustion chambers, they are nonetheless substantial because of the very large quantity of fuel consumed in this process. Present projections show a 5.7 percent annual increase in fuel consumption for coke ovens.

Open hearth furnaces are now being replaced in the U.S. steel industry by the basic oxygen furnace, but are still an important source of NO_x emissions because of the very high combustion air preheat temperatures, high operating temperatures, and the practice of oxygen lancing. Fuel consumption in open hearth furnaces is presently decreasing about 8 percent per year.

Soaking pits and reheat furnaces are used to heat steel billets and ingots to correct working temperatures prior to forming. Current trends are toward continuous casting of molten metal, and the need for these units is being eliminated. At present however, soaking pits and reheating furnaces still consume more fuel than any other single process in the steel industry. In spite of the fact that soaking pits and reheat furnaces are being phased out, consumption of process fuel continues to increase at an annual rate of about 2.8 percent in the iron and steel industry as a whole.

2.1.6.1.2 Glass Industry

In the glass industry, melting furnaces and annealing lehrs are the two fuel combustion processes of greatest importance. Melters in the glass industry are continuous reverbatory furnaces fueled by natural gas and oil. Coal is not suitable for these furnaces because of its inherent impurities. Annealing lehrs control the cooling of the formed glass to prevent stains from occuring. Some lehrs are direct-fired by atmospheric, premix, or excess-air burners. About 80 percent of the total industry fuel consumption goes for melting, while annealing lehrs consume about 15 percent. There is a current trend in the glass industry towards electric melters, or at least electrically-assisted conventional melters. But until it becomes clearer which fuels are going to be available in the future, no definite trends will emerge. Present trends toward fuel oil in place of natural gas have begun as a result of natural gas shortages and price increases.

2.1.6.1.3 Cement Industry

Cement kilns are the major combustion processes in the cement industry. These kilns are rotary cylindrical devices up to 230 m (750 feet) in length which contain a feedstock combination of calcium, silicon, aluminum, iron, and various other trace metals. This mixture of elements in the form of various combinations of clay, shale, slate, blast furnace slag, iron ore, silica sand, limestone, and chalk slowly moves through the kiln as products of fossil fuel combustion move in an opposite direction. Temperatures of the material during the process may reach 1,756K (2,700F).

Coal, fuel oil, and natural gas are the main fuels used in cement kilns. Natural gas accounts for 45 percent of the fuel consumed, coal for 40 percent, and fuel oil for 15 percent. The major effluent stream for this process is the exhaust gas which passes through the entire length of the kiln and may entrain additional particulate or trace metals from the kiln feedstock. Cement industry figures show that the industry has grown an average of about 1.9 percent annually over the past 20 years. Industry projections, however, predict a greater growth in the next few years of between 2.6 to 4.1 percent per year (Reference 2-34).

2.1.6.1.4 Petroleum Refineries

A wide variety of process combustion takes place in the petroleum refining industry, including catalyst regenerating in the catalytic cracker, catalytic reforming, process heating, delayed coking, and hydrotreating and flaring of waste gases. Catalytic cracking is required for a large portion of gasoline production. Fuel is consumed in this operation in the catalyst regeneration procedure which removes coke and tars from the catalyst surface. Temperatures during this process are moderate, ranging from 840 to 922K (1,050 to 1,200F), but fuel requirements are on the order of 829 kJ/l (150,000 Btu/Bbl) feedstock. Catalytic cracking capacity increased about 1.7 percent per year between 1960 and 1973. Future growth will depend on energy and environmental policy and particularly the demand for low sulfur fuel oil. Present estimates of future growth are from 1 percent to 3.0 percent per year (Reference 2-34).

Catalytic reforming, where certain saturated ring hydrocarbons are converted into aromatic compounds, typically utilizes oil, gas, or electricity as its primary fuel. Process heaters serve to heat refinery process streams prior to distillation. They are generally large combustion units firing heavy residual oil and high sulfur-bearing gas streams. Delayed coking is an energy extensive process which uses severe cracking to convert residual pitch and tar to gas, naptha, heating oil and other more valuable products. Hydrotreating is a process designed to remove impurities such as sulfur, nitrogen, and metals to prepare cracker or reformer feedstock.

Process heating fuels used by the refinery industry are primarily natural gas and refinery gas, along with some residual oils and petroleum coke. Projections are for a 2.7 percent annual increase in process heating to 1980, and 2.9 percent per year to 1985 (Reference 2-34). The fuel mix for the future is highly dependent on both availability and costs of the preferred fuels, and is therefore very difficult to project until national energy priorities are established and the question of natural gas price regulations is settled.

2.1.6.1.5 Brick and Ceramic Kilns

Brick and ceramic kilns for curing clay products are other major users of process heating fuels. Products of these kilns include structural bricks, structural and facing tile, vitrified clay pipe, and other related items. Typically a kiln is operated in conjunction with a drier which recovers part of the heat contained in the exhaust gases. Kilns are fueled by coal, oil, or gas (depending on the availability of fuel and the product being cured) for batch runs of 50 to 100 hours at temperatures around 1,367K (2,000F). Combustion products are ducted from the kiln to a drier, where wet clay products undergo an initial drying procedure. Occasionally, when higher temperatures are needed for drying, a secondary combustion process is used in the drier itself.

Since brick production in the past has shown a strong correlation with the country's economic health, reliable projections of future growth for the industry are difficult to make.

2.1.6.1.6 Sulfuric Acid Manufacture

Sulfuric acid, H_2SO_4, is manufactured by contact processes which are classified by their feedstocks: elemental sulfur burning, spent acid and hydrogen sulfide burning, and sulfide ore and hydrogen sulfide smelter gas burning. These three processes account for 68 percent, 18 percent, and 14 percent of domestic production, respectively. Total U.S. production of H_2SO_4 in 1974 was estimated to be 29.1 Tg (32,000,000 tons), the bulk of which was used by phosphate fertilizer manufacturers, chemical manufacturers, and the iron and steel industry.

Combustion related emissions — including NO_x — are a result of the initial burning of the sulfur in the feedstock with natural gas or fuel oil. The growth of sulfuric acid industry is estimated at 4.6 percent per year through 1980 (Reference 2-35).

2.1.6.2 Effluent Stream Characterization

In all cases of process combustion described above, the only effluent stream from the combustion process is the combustion product stream itself. In those cases where high particle loading occurs as a result of coal combustion or dust entrainment (bricks, cement), a collection device is normally used on the stream, producing either an additional liquid or dry solid effluent stream.

For several processes, additional contaminants such as trace metals enter the stream from the product, as in cement kilns or glass melters. Because of process requirements, these contaminants are expected to continue to enter the gas stream whether or not combustion control measures are implemented. Table 2-11 lists the combustion-related effluent streams associated with each of the industrial processes described above.

2.1.7 Advanced Combustion Processes

Several alternate or advanced energy systems are currently in various stages of development, and a number of these are expected to see commercial applications in the 1980's and 1990's. Here, the most important of these processes and their related equipment will be discussed in terms of their possible impacts on pollutant emissions. A more detailed process description and review of NO_x control options for these systems are given in Section 4.

There are two alternate energy systems which are already commercially available:

- Repowering
- Pressurized boilers

In addition, three other processes are expected to become available within the next decade which will have significant potential impact on pollutant emissions:

- Combined cycles/coal gasification
- Fluidized bed combustion
- High temperature gas turbines

Processes which may eventually become commercially feasible alternatives, but which still require a good deal of development, include:

- Catalytic combustion
- Magnetohydrodynamics
- Binary cycles

Table 2-12 shows the state of development of each of these advanced combustion systems.

The following subsection briefly describes each process and its projected operating characteristics, if available. In addition, current prospects for implementing each process are given. Since there is little or no commercially installed capacity for these processes, they are not included in emission quantifications presented in Section 5. However, subsequent emissions projections

TABLE 2-11. SIGNIFICANT INDUSTRIAL PROCESS HEATING EQUIPMENT TYPES

	Gaseous Effluent Stream Description
Iron and Steel Industry	
Coke oven underfire	Combustion products
Sintering	Combustion products and entrained substances from feedstock
Open hearth furnaces	Combustion products and entrained substances from feedstock
Soaking pit and reheat ovens	Combustion products
Glass Industry	
Melters	Combustion products and entrained substances from feedstock
Annealing lehrs	Combustion products
Cement Industry	
Kilns	Combustion products and entrained substances from feedstock
Petroleum Refining	
Catalytic cracking	Combustion products and volatilized products or catalysts
Process heaters	Combustion products
Brick and Ceramics	
Kilns	Combustion products and entrained substances from driers and feedstock

TABLE 2-12. ADVANCED COMBUSTION SYSTEMS — STATE OF DEVELOPMENT

Repowering	Currently available[a]
Pressurized boilers	Currently available[b]
Low Btu coal gasification	Pilot plants, late 1970's[c]
Fluidized bed combustion	Pressurized demo plant 1981[c]
Advanced HT gas turbine steam cycle	Commercially available 1984
Binary cycle	
Topping	Demo plant 100 MW 1981
Bottoming	Demo plant 1981
MHD open cycle	50 MW demo plant 1984
Catalytic combustion	Gas turbine demonstration 1980[d]

[a] Reference 2-38
[b] Reference 2-37
[c] Reference 2-36
[d] Aerotherm estimate

will include these units as emission sources. Also, a special process engineering report will be done as part of this NO_x E/A to address the developmental status and the projected economic and environmental problems for these processes.

Repowering

Repowering is broadly defined as the addition of a combustion turbine to an existing steam plant, involving the mechanical or thermal integration of the combustion or steam cycles (Reference 2-39). More specifically, repowering has meant the conversion of an existing steam boiler or boilers in the power output capacity range of 30 to 75 MW to an unfired heat recovery steam generator (HRSG) with the addition of a conventional simple cycle gas turbine (or turbines) in the output capacity range of 15 to 120 MW. This turbine is used to drive a mechanical electrical generator and exhausts to the HRSG. In another variation known as supplementary firing, a turbine is added, but the firing capabilities of the boilers are maintained. Still another variation — less efficient than the previous two — uses part of the gas turbine exhaust to preheat the HRSG feed water and the remainder to operate the boiler. There are a number of advantages to repowering existing systems (Reference 2-38):

- Large capital outlay for new equipment, facilities, and sites may be deferred until present uncertainties in electrical utility growth demands are resolved
- New order lead time is reduced
- Equipment heat rate is improved and environmental impact is reduced
- Flexibility is improved and firm power reliability increased, since the gas turbine may be run independently

The characteristic effluent streams emitted by both conventional gas turbines and boilers will be present in the combined systems, although supplementary firing will result in different combustion characteristics than in conventional boilers.

Pressurized Boilers

Pressurized boilers, often referred to as supercharged boilers, operate at furnace pressures up to about a million Pascal, or about 10 atmospheres. Presently, several of these units are being operated in Europe (Reference 2-37), but none of the utility size are installed in this country. This design has several advantages over conventional boilers, including increased heat transfer within the furnace, higher volumetric heat release, and reduced boiler size. Pressurized boilers are particularly suited to gas and oil or other fuels which can be introduced into the combustion furnace under pressure. In the U.S., it appears that the major application of pressurized boilers will involve fluidized bed combustion discussed below.

Fluidized Bed Combustion

In fluidized bed combustion, air is blown through a bed of granular noncombustible material, such as coal ash or lime, causing the granulated bed particles to become suspended. Fuel, normally crushed coal, is pneumatically injected near the bottom of the bed where it is combusted at temperatures between 1,033 to 1,367K (1,400 to 2,000F). Although the flyash particles entrained in the combustion gases from fluidized bed combustion have a high carbon content, these particles are trapped in particulate collection devices and reinjected to ensure efficient combustion. Sulfur control through an SO_2 sorbent bed such as $CaCO_3$ or dolomite is a distinct possibility, and reduction of thermal NO_x is a direct result of the inherently low combustion temperature of the fluidized bed process. Operating pressures range from atmospheric to as high as 25 atmospheres. Higher pressure units are designed to be used in a combined gas turbine steam cycle in which the fluidized bed unit will act as an external combustor for the gas turbine and a steam generator for the steam turbine. Fluidized bed combustion – especially the pressurized design – offers several advantages, including:

- High heat transfer rates and volumetric heat release
- Reduction of ash fouling and high temperature corrosion as a result of low combustion temperatures
- Ability to burn lower grade fuels more readily than conventional boilers

Coal Gasification/Combined Cycle Gas Turbines

Low-Btu gas from coal is rich in hydrogen and carbon monoxide, with a heat content of 4.7 to 14.9 MJ/m^3 (125 to 400 Btu/ft^3). It is the product of the partial combustion of a mixture of coal, air, and steam. This gas can be converted into pipeline quality gas by two additional processes, water gas shift and methanation. Long-term economical advantages, however, will come from onsite production of low-Btu gas for combined cycle gas turbines.

There are three candidate processes for producing gas from coal as a fuel for both conventional steam plants and combined cycle turbine-steam plants. These processes are known as fixed bed, entrained bed, and fluidized bed gasification. In addition, the chemically-active fluidized bed (CAFB) gasifier shows promise for use with high sulfur coal. CAFB gasification, when used with high sulfur petroleum residuum or asphalts, is expected to remove up to 95 percent of the sulfur and a large portion of the vanadium as well as other trace metals.

High Temperature Gas Turbine Steam Cycle

High temperature gas turbines for use on combined gas turbine steam cycles firing low-Btu gas are currently projected to be commercially available about 1984. Present combined cycle units are economically feasible only for intermediate range plants, but increasing inlet temperatures to 1,972K (3,000F) would improve unit efficiency to about 50 percent. Coupling this new design to a nearby low-Btu gasification plant would give a total plant efficiency of about 38 percent (Reference 2-36), which compares favorably to present day coal-fired steam plants. The high temperature of the combustion zone in this kind of a unit, however, would increase thermal NO_x formation for which dry controls or water injection techniques have not been developed.

Catalytic Combustion

Catalytic combustion is being vigorously pursued for application to gas turbine combustors and area sources. By total premixing of the fuel and air, temperatures in the adiabatic catalytic combustion section can be lowered to approximately the turbine inlet temperature, and effectively eliminate thermal NO_x generation. The system relies on the catalyst to rapidly and completely combust the typically lean mixtures that result from the total premixing. Excellent catalyst performance at temperatures up to 1,756K (2,700F) has been demonstrated for short periods of time (75 hours) in feasibility studies (Reference 2-40).

MHD Open Cycle

Magnetohydrodynamic (MHD) generators convert mechanical energy to electrical energy by the interaction between a moving conducting fluid and a stationary magnetic field. Open cycle processes may use fossil fuel combustion products directly as a conducting fluid simply by seeding with an ionized salt of potassium or cesium. A waste heat boiler is used in conjunction with the MHD unit to recover thermal energy from the exhaust gases. Projected cycle efficiencies are 50 percent with potential for as high as 60 percent in the long term.

Binary Cycle

There are two types of binary cycles: the topping cycle, which uses a high temperature cycle to "top" a low temperature cycle; and the bottoming cycle, which uses ammonia and the exhaust heat of a steam cycle. Each of these processes can increase conventional steam plant efficiencies to

50 or 60 percent. Although these conversion techniques will have little affect on the combustion process themselves, the increased efficiency achieved will reduce pollutant emissions accordingly.

2.1.8 Incineration

Nearly 50 percent of the urban and industrial waste generated in the U.S. is burned in incinerators (Reference 2-41). Incineration is given secondary emphasis in this assessment. Emission estimates are given in Section 5.4 for comparison with other NO_x sources. The major types of incineration equipment are:

- Municipal incinerators — single or multiple chamber units with a capacity of greater than 45 Mg per day and typically incorporating some form of particulate control device
- Industrial/commercial incinerators — single or multiple chamber units having a capacity of from 23 Kg to 1,800 Kg per hour and occasionally have emission control devices
- Miscellaneous trench, domestic, flue fed, pathological, or controlled air incinerators

2.2 MOBILE COMBUSTION SOURCES

Mobile combustion sources are the second major cause of atmospheric NO_x emissions. Although this sector is not within the scope of the assessment, it is defined in this section and NO_x emission estimates from mobile sources are included in Section 5.4 to accurately compare stationary and mobile sources.

Mobile sources include both highway and nonhighway vehicles. Highway vehicles can be divided into the following categories:

- Passenger cars and light trucks powered by gaseous (LPG, CNG, LNG), diesel or gasoline fuels
- Heavy duty trucks powered by gaseous (LPG, CNG, LNG), diesel or gasoline fuels
- Motorcycles powered by gasoline

Nonhighway vehicles can be divided into the following subcategories:

- Aircraft
- Locomotives
- Vessels — further divided into inboard and outboard
- Small general utility engines — snowmobiles, minibikes, dunebuggies, small electric generators, etc.

2.3 NONCOMBUSTION SOURCES

Noncombustion NO_x emissions are produced by several primary chemical manufacturing processes. Although none of these processes are significant on a national scale in terms of absolute emissions, they are often cited as serious local sources of pollution. The most important of these processes are:

- Nitric acid manufacture
- Adipic acid manufacture
- Explosives manufacture

Certain secondary chemical processes are also sources of NO_x, including fertilizer manufacture and various chemical nitration processes.

Since these noncombustion sources of NO_x are of interest to this assessment for making comparisons of relative emissions, they will be carried through to the Section 5 emission inventory.

Nitric Acid Manufacture

Nitric acid, HNO_3, is manufactured in the U.S. by the oxidation of ammonia. The primary uses of this acid are for nitrate fertilizers (~60 percent); industrial explosives (~15 percent); and various organic chemical manufacture, steel pickling, and military munitions (25 percent). Emissions from nitric acid plants are not significant on a national scale, but on a local basis they are frequently of great concern. The tail gas or off-gas emanating from the HNO_3 plant contains about 0.3 percent NO_x (NO, NO_2). Catalytic burners are typically used to control NO_x on these plants by reducing the NO_2 concentration of the tail gas to produce a colorless stream consisting mostly of N_2, O_2 and CO_2.

The projected growth rate for the industry is 7.2 percent annually.

Adipic Acid Manufacture

Adipic acid $(CH_2)_4\ (COOH)_2$, is manufactured by the catalytic oxidation of cyclohexane, with cyclohexanone and cyclohexanol as intermediates. Greater than 90 percent of the adipic acid production is used to manufacture nylon 6/6, while the remainder is used for various plasticizers, synthetic lubricants, etc. Although emissions from adipic acid plants may not be significant on the national scale, they may be very serious on a localized basis, as only five plants produce nearly 1.5 billion tons annually (Reference 2-42). The NO_x produced by the initial oxidation step of the process is stripped from the adipic acid/nitric acid solution with air and steam. NO and NO_2

are recovered by absorption in nitric acid as part of the process rather than as a pollution control measure. The industry as a whole has undergone a recent slowing of a historically rapid growth, dropping from an approximate 7 percent annual growth from 1965 to 1971 to an expected 4 percent per year growth rate over the next three years (Reference 2-42).

Explosives Manufacture

Explosives can be divided into four primary classifications: bulk explosives, propellants, initiating agents, and specialty explosives. The major bulk explosives and propellants are nitroglycerine, nitrocellulose, 2-, 4-, 6-trinitrotoluene, and cyclotrimethylene trinitrimine. The remainder of the explosives classifications is produced in quantities much smaller than those mentioned and will not be considered here.

The bulk explosives and propellants are manufactured by essentially the same process, which consists of reacting concentrated acids with an organic material in a nitration step. Acid fumes result from the nitration step, and are a form of pollutant emission if they are not recovered and recycled. Growth in the explosives industry is highly dependent on a number of fluctuating factors and therefore cannot be accurately projected.

2.4 FUGITIVE EMISSIONS

The final source of atmospheric NO_x emissions is man-made and natural fugitive emissions. These sources are generally uncontrolled except through elimination of the source and are not within the scope of the present assessment. Estimates of the NO_x emissions from these sources will be made in Section 5.4 for comparison with other NO_x sources.

Man-made sources of fugitive NO_x emissions include:

- Open burning of municipal waste, landscape refuse, agricultural field refuse, wood refuse, and bulky industrial refuse
- Grain elevators
- Forest fires — both accidental and controlled burns
- Structural fires — both accidental and planned
- Minor processes — such as welding and acid pickling

Natural fugitive emissions result from nitrogen fixation in the biological nitrogen cycle and from lightning (References 2-43 and 2-44).

2.5 CONCLUSIONS AND SUMMARY

This section presents final comments on the general quality and comprehensiveness of the data used to make the selection of equipment categories for the subsequent parts of this NO_x E/A. A summary of the significant stationary fuel combustion equipment categories and their major fuels specified in this section is presented.

2.5.1 Data Evaluation

In general, the quality of data reviewed during the screening of various equipment sectors was adequate for this preliminary characterization. The data on new equipment design characteristics and operating practice was good. The data on field population and operating practice for older equipment was only marginal and will need to be augmented as part of the subsequent process studies.

The utility boiler category — the most important from a NO_x standpoint — is generally very well documented, especially in the areas of fuel consumption and composition, electrical power generation, and installed capacity. One large data gap exists, however, in furnace design characteristics for older equipment. Although general information is available, specific data on furnace populations and distribution, unit load factors, use of mixed fuel firing, and furnace design trends are difficult to obtain. The data gap was filled, in part, by industry contacts, but more complete information is needed. A further weakness is the lack of available information on fuel use practices, particularly statistics on fuel origin, blending, switching, and backup. Finally, potentially valuable information on how new equipment is put online and older equipment retired, was generally unavailable.

Since there are more kinds of packaged boilers than any other type of equipment, the completeness of the data on packaged boilers is more questionable than the data for any other sector. A further difficulty with packaged boilers is the fact that the equipment is categorized differently in different studies. The data available for new unit sales are comprehensive. However, only sparse information is available on boiler fuel switching, retirement practices, operational maintenance, or burner distribution. As a result, the final selection of equipment is based strongly on recent sales. This should make it applicable to the future emission control studies, in spite of the relative lack of data.

Warm air furnace equipment selection is mainly based on the most recent U.S. Census estimate, and is considered to be of highest quality. Statistically, because of the very large number of units being considered, this sector is undoubtedly very accurate. Data on other residential and commercial combustion equipment included in this sector also come from the U.S. Census Bureau.

However, the data are considered to be of fairly low quality in terms of combustion-generated air pollution because of the lack of specific details, particularly for the fuel consumed by various equipment types. Additional information for these other residential and commercial combustion equipment types is required to complete this sector.

Data on the gas turbine sector are considered to be fairly accurate as a result of recent installed capacity estimates in the Gas Turbine Standard Support Document. One obvious data gap, however, is the absence of information on the smaller capacity units and their operational practices. Because the availability of clean fuel and pending air pollution regulations are uncertain, the growth of the gas turbine industry is difficult to predict. Further information regarding electric utility practice during peaking periods, fuel or equipment switching during times of low air quality, and combined-cycle use is needed to make the data on this sector complete.

Data for the reciprocating IC engine sector came for the most part from the recent standard support document and are considered to be of relatively high quality. Application, installed capacities, load factors, and fuels are well documented. Very small gasoline engines, like those used on lawn mowers, chain saws, etc., have been excluded because statistics on their distribution and use are impossible to obtain. This exclusion, however, should have very little effect on the sector totals.

Data on the process heating sector are of good quality for the processes included in this report. A number of minor processes were excluded from this sector because of their relatively small applications. The major processes, however, and those which may be subject to combustion control in the future, have been included so that the major portion of the sector should be covered.

Although noncombustion processes far outnumber those discussed in this report, the major ones have been included. Of greatest concern in this sector are those processes, like nitric acid plants, which may cause serious local pollution problems.

The other equipment or process sources of NO_x mentioned here are not covered extensively, but included for completeness. As a result, extensive data have not been gathered. In most cases, however, existing data on many of these less important areas are limited at best.

2.5.2 Tabulation of Stationary Fuel Combustion Equipment Categories

The preliminary characterization of the seven major fuel combustion equipment categories has identified equipment designs having significantly different potential for formation and/or control of combustion-generated pollutants. Table 2-13 shows the resulting equipment/fuel categories

TABLE 2-13. SIGNIFICANT STATIONARY FUEL COMBUSTION EQUIPMENT TYPES/MAJOR FUELS

Utility Sector (Field Erected Watertubes)	Fuel
Tangential	PC, O, G
Wall fired	PC, O, G
Horizontal opposed and Turbofurnace	PC, O, G
Cyclone	PC, O
Vertical and stoker	C
Packaged Boiler Sector	
Watertube 29 to 73 MW[a] (100M to 250 MBtu/hr)	PC, O, G, PG
Watertube <29 MW[a] (<100 MBtu/hr)	C, O, G, PG
Firetube scotch	O, G, PG
Firetube HRT	C, O, G, PG
Firetube firebox	C, O, G, PG
Cast iron	O, G
Residential	C, O, G
Warm Air Furnace Sector	
Central heaters	O, G
Space heaters	O, G
Other residential combustion	O, G
Gas Turbines	
Large >15 MW[a] (>20,000 hp)	O, G
Medium 4 to 15 MW[a] (5,000 to 20,000 hp)	O, G
Small <4 MW[a] (<5,000 hp)	O, G
Reciprocating IC Engines	
Large bore >75 kW/cyl[a] (>100 hp/cyl)	O, G
Medium 75 kW to 75 kW/cyl[a] (100 hp to 100 hp/cyl)	O, G
Small <75 kW[a] (<100 hp)	O, G

TABLE 2-13. Concluded

- Industrial Process Heating
  - Glass melters
  - Glass annealing lehrs
  - Cement kilns
  - Petroleum
    - Catalytic crackers
    - Process heaters
  - Brick and ceramic kilns
  - Iron and steel coke oven
    - Underfire
  - Iron and steel sintering machines
  - Iron and steel soaking pits and reheat ovens

PC — Pulverized coal
C — Stoker coal or other coal
O — Oil
G — Gas
PG — Process gas

[a] Heat input

which may merit separate consideration in the subsequent emission inventories, process studies and test programs. Generally, obsolete designs and minor equipment types not expected to play a role in future NO_x control programs have been included as subsets of the major categories shown. The other NO_x sources play only a peripheral role in the NO_x E/A and were not categorized beyond the course groupings listed in the introduction to this section.

REFERENCES FOR SECTION 2

2-1. Bartok, W. et al., "Systems Analysis of Nitrogen Oxide Control Methods for Stationary Sources — Volume II," prepared for National Air Pollution Control Administration, NTIS-PB 192 789, Esso, 1969.

2-2. "OAQPS Data File of Nationwide Emissions, 1971," Office of Air Quality Planning and Standards, Environmental Protection Agency, May 1973.

2-3. Emission Data from the National Emission Data System (NEDS), EPA, Research Triangle Park, North Carolina, 1976.

2-4. Shimizu, A. B. et al., "NO_x Combustion Control Methods and Costs for Sources; Summary Study," EPA-600/2-75-046, NTIS-PB 246 750/AS, September 1975.

2-5. "Air Quality and Stationary Source Emission Control," U.S. Senate Public Works, 94:1, 94-4, March 1975.

2-6. Personal communication with H. J. Melosh III, Foster Wheeler Corporation.

2-7. Locklin, D. W. et al., "Design Trends and Operating Problems in Combustion Modification of Industrial Boilers," EPA-650/2-74-032, NTIS-PB 235 712/AS, Battelle, April 1974.

2-8. Breen, B. P., "Combustion in Large Boilers: Design and Operating Effect on Efficiency and Emissions," 16th International Symposium on Combustion, Cambridge, Massachusetts, August 1976.

2-9. "Applicability of NO_x Combustion Modification to Cyclone Boilers (Furnaces)," Monsanto Research Corporation, 1976.

2-10. Surprenant, Norman et al., "Preliminary Emissions Assessment of Conventional Stationary Combustion Systems, Volume II, — Final Report," EPA-600/2-76-046b, NTIS-PB 252 175/AS, March 1976.

2-11. "Evaluation of National Boiler Inventory," EPA-600/2-75-067, NTIS-PB 248 100/AS, Battelle Columbus Laboratories, October 1975.

2-12. "Power" Magazine Plant Design Issues, 1971.

2-13. Personal communication with R. Hall, EPA-RTP (EEI Data), November 1976.

2-14. Personal communication with G. Bouton, Babcock & Wilcox, December 1976.

2-15. Personal communication with G. Devine, Combustion Engineering, December 1976.

2-16. Personal communication with F. Walsh and R. S. Sadowski, Riley Stoker Corporation, November 1976.

2-17. Personal communication with S. Barush, Edison Electric Institute, December 1976.

2-18. McKnight, J. S., "Effects of Transient Operating Conditions on Steam-Electric Generator Emissions," EPA-600/2-75-022, NTIS-PB 247 701/AS, Research Triangle Institute, August 1975.

2-19. Personal Communication with R. R. Vosper, Coen Company, January 1977.

2-20. "Field Investigation of Emissions from Combustion Equipment for Space Heating," EPA-R2-73-084a, NTIS-PB 223 148, Battelle Columbus Laboratories, June 1973.

2-21. "Current Industrial Reports, Steel Power Boilers," 1968-1975, U.S. Department of Commerce, Bureau of the Census.

2-22. Shields, C.D., "Boilers, Types, Characteristics and Functions," McGraw Hill, 1961.

2-23. Cato, G. A. et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers — Phase I," EPA-650/2-74-078a, NTIS-PB 238 920/AS, KVB Engineering, October 1974.

2-24. "Statistical Highlights — Ten Year Summary 1963-1972, and Total Industry Factory Shipments in Units," Gas Appliance Manufacturers Association, January 1974.

2-25. Dupree, W. G., and J. S. Corsentino, "Energy Through the Year 2000 (Revised)," Bureau of Mines, December 1975.

2-26. "Statistical Abstract of the United States 1975," 96th Annual Edition, U.S. Department of Commerce, Bureau of the Census, 1975.

2-27. "American Gas Association Research and Development 1976," American Gas Association, 1976.

2-28. "FPC News," Volume 8, No. 23, June 6, 1975.

2-29. Durkee, K. R., et al., "Standards Support and Environmental Impact Statement — An Investigation of the Best Systems of Emission Reduction for Stationary Gas Turbines," EPA Office of Air Quality Planning and Standards, July 1976.

2-30. "1975 Sawyer's Gas Turbine Catalog," Gas Turbine Publications, Inc., Stamford, Connecticut, 1975.

2-31. "Diesel & Gas Turbine Worldwide Catalog," Volume 41, Oshkosh, Wisconsin, 1976.

2-32. Offen, G. R., et al., "Standard Support Document and Environmental Impact Statement — Reciprocating Internal Combustion Engines," Aerotherm Project 7152, Acurex Corporation, November 1975.

2-33. Ketels, P. A., et al., "A Survey of Emissions Control and Combustion Equipment Data in Industrial Process Heating," Institute of Gas Technology, June 1976.

2-34. Foley, G., "Industrial Growth Forecasts," Stanford Research Institute, Contract No. 68-02-1320, September 1974.

2-35. Hopper, Thomas G. and William A. Morrone, "Impact of New Source Performance Standards of 1985 National Emissions from Stationary Sources," Vol. I, Final Report (Main text and Appendices I through III), October 1975.

2-36. "The National Power Survey Energy Conversion Research," Federal Power Commission, June 1974.

2-37. Pfenninger, H., and G. Yannakopoulos, "Steam Power Stations With Pressure-Fired Boilers," (reprinted from Brown Boveri Publication No. CH-T020053 E) Combustion, September 1976.

2-38. Ahuja, Ashok, "Repowering Pays Off for Utility and Industrial Plants," Power Engineering, July 1976.

2-39. Gerstin, R. A., "A Technical and Economic Overview of the Benefits of Repowering," ASME 75-GT-16.

2-40. "Development of Catalyst and System Design Criteria for Catalytic Combustors with Application to Stationary Sources," Aerotherm/Acurex Monthly Progress Report 7135-18, Contract 68-02-2116.

2-41. "Compilation of Air Pollutant Emission Factors (Second Edition)," U.S. Environmental Protection Agency, AP-42, April 1973.

2-42. Durocher, D., et al., "Screening Study to Determine Need for Standards of Performance for New Adipic Acid Plants," GCA-TR-76-16-G.

2-43. Robinson, E. and R. C. Robbins, Journal of Air Pollution Control Association, 20, 303, 1970.

2-44. Skinner, K. J., "Nitrogen Fixation," Chemical & Engineering News, October 1976.

SECTION 3

POLLUTANT CHARACTERIZATION

Stationary combustion sources produce a variety of effluents which, depending on the locale, may have effects on the environment ranging from negligible to significant. To determine the incremental impact of applying NO_x controls to stationary combustion sources, the environmental effects of both controlled and uncontrolled sources must be evaluated. This requires first an inventory of the emissions from the sources and then a means to relate these emissions to changes in the environment. Even though the impact of stationary source combustion facilities on the environment has been the subject of intense controversy for over a decade, wide gaps exist in our knowledge of both the quantities and the effects of their emissions on the environment. This report summarizes the current state of the art in both areas. Section 3 will concentrate on potential effects of these emissions on the environment; existing data on combustion-related emissions, with and without NO_x controls, are summarized in Sections 5 and 6.

Although this section contains information on the impact of various pollutants, it is not an environmental impact statement in the traditional (NEPA) sense. The NO_x environmental assessment is intended to provide a general view of the need for NO_x controls and the potential for creating additional problems as NO_x emissions are reduced. The program generally considers various categories of combustion sources and rarely focuses on one specific site. Environmental effects are therefore generalized and individual sites may be found where problems are either enhanced or reduced because of local conditions. The consideration of local ecology and the effects of a specific combustion source will be left to traditional environmental impact statements for that site. In addition, since this report considers diverse equipment types and potential sites, a different approach has been taken to set threshold values. The usual approach works from the process emissions, using dispersion estimates to get ambient concentrations. The ambient concentrations are then compared to threshold pollutant levels, which then determines whether controls are needed. In this specific effort, we are attempting to work backwards.

Section 3 attempts to assess the available data on human health effects and terrestrial and aquatic ecosystem responses to estimate potentially significant concentration ranges. These estimates will then be used to alert control system designers if NO_x controls cause other pollutants to approach significant concentrations. The concentrations indicated in Section 3 will be used to evaluate and compare NO_x control approaches which may produce other pollutant problems. This evaluation will remain somewhat subjective, since the data base is inadequate to support precise quantitative decisions.

The pollutant levels defined in Section 3 will be used to determine sampling requirements for airborne, liquid, and solid effluent streams in the tests to be performed under the NO_x E/A program. The threshold levels will also be used to help order the matrix of combustion sources and control options considered in Section 7 of this report. The data presented herein are preliminary, however, and deserve further refinement before they are used extensively for other than program planning. The present data will be substantially expanded as the NO_x E/A progresses.

The bioassay work to be performed on actual combustion source effluents will provide a better understanding of actual pollutant effects, particularly pollutant synergisms or antagonisms. Impact assessment work could thus overlap other ongoing environmental assessments, so that close coordination between programs becomes important. It is also possible that the information obtained on other studies could substantially augment the data base available for this study.

A preliminary search of the literature on environmental impacts has been made, and the results will be discussed in the remainder of Section 3. To lay the foundations for the quantitative data presented later, Section 3.1 considers possible pollutants which may be attributed to stationary source combustion and Section 3.2 describes the research methodologies used to establish exposure levels. Section 3.3 summarizes the results available to date, while Section 3.4 discusses these data and recommends some short-term activities under this program to improve their quality.

3.1 POLLUTANT IDENTIFICATION AND TRANSFORMATION

Many chemical compounds, comprised of diverse elements, have at one time or another been identified as components of effluent streams from stationary source combustion. These substances can be considered in four general categories:

- Gaseous effluents from normal operation (CO, CO_2, H_2O, NO, NO_2, SO_2, SO_3)
- Inorganic compounds from the ash component of the fuel
- Organic compounds generated by incomplete combustion of the fuel, primarily in off-design operation (especially transient and upsets)

- Solid and liquid effluent streams (boiler wash, SO_2 scrubbing residue, etc.)

The existence of a species in measurable concentrations may vary widely, depending on source type, fuel type, operating load, maintenance procedures, and types of production control equipment employed.

For some NO_x control methods, little or no data on pollutant emissions are available. To insure that potentially harmful, but presently unidentified pollutants do not escape analysis because of lack of data, this report will consider a wide list of possible pollutants. This list, presented in Table 3-1,* will be used to determine which pollutants should be considered when effects on human health and terrestrial and aquatic life are evaluated.

Table 3-1 is set up by general classes of compounds and then divided into specific compounds, where warranted by the data. Typical sources of the pollutant, emission stream, and whether the compound is emitted during normal or nonstandard operations are shown. Where possible, typical emission ranges are shown, along with the estimated persistence of the primary pollutant and the measured values of ambient concentration where known (based principally on measurements in the Los Angeles Basin). These ambient concentrations are from all sources, although the percentage which can be attributed to combustion sources has been estimated in the adjacent column.

It should be emphasized that large variations in ambient concentrations of air pollutants can occur, depending on proximity to the source, meteorological conditions, location within the U.S., time of day, etc. Consequently, the values given are subject to large variation, but provide some typical ranges. The ambient data were taken from the California Aerosol Characterization Experiment (ACHEX) Study (References 3-1 and 3-2), and "California Air Quality Data" (Reference 3-3); detailed hydrocarbon data for the Los Angeles Basin were determined by the EPA and the California Air Resources Board (CARB); and elemental composition data were taken from Flocchini, Cahill, et al., (Reference 3-4), as well as the ACHEX study. Data on some of the more exotic species were taken from the report of Hanst, et al., (Reference 3-5).

The persistence of both primary and secondary pollutants has been estimated qualitatively. The tabulated values of low, medium, and high persistence correspond approximately to ranges of <0.1, 0.1 to 1.0, and >1.0 days respectively. For the organic hydrocarbons, persistence is defined in terms of half-life, based on reaction with the hydroxyl radical.

Finally, Table 3-1 shows a list of known or speculated secondary pollutants (which may result from the listed primary pollutants), their concentrations relative to the precursor pollutants,

---

*Table 3-1 is not intended to be definitive. It will be revised as work proceeds and the species list will be expanded or contracted as required. Many entries which are currently blank will be completed as further data are obtained.

75

TABLE 3-1. PRELIMINARY POLLUTANT CATALOG
a. NITROGEN CONTAINING COMPOUNDS

Species	Source	Stream	Occurrence		Emissions Quantity (ppm)	Primary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
			Standard Operations	Nonstan. Operations									
NO	Coal Oil Gas	Flue gas	X		<1000	Medium	0.01-1.0	≈50	NO_2 HNO_2 Organic nitrites	Large Small Very small	Medium Low Low	 <.001 <.01	
NO_2	Coal Oil Gas	Flue gas	X		~100	Medium	0.01-1.0	≈50	HNO_3 Organic nitrates PAN Particulate nitrates (e.g., NH_4NO_3, $NaNO_3$)	Small Very small Small Medium	Low Medium Medium Medium	≈.03 <.01 <.05 1-20 μgm^{-3}	
NH_3	Coal Oil Gas	Flue gas	X		<100	Low	0.006-0.01		$[NH_4]_2\ SO_4$ NH_4NO_3	Large Large	Medium Medium		
HCN	Coal Oil Gas	Flue gas	X		Small	High							
Amines	Coal Oil	Flue gas	X		Small	Medium	<0.005	<5	Nitrosamines	Small	Medium	<.001	
Nitrous Acid	Coal	Flue gas	X		Small	Low	<0.01	<10	NO, NO_2	Large	Medium		

TABLE 3-1. PRELIMINARY POLLUTANT CATALOG
b. SULFUR CONTAINING COMPOUNDS

Species	Source	Stream	Occurrence: Standard Operations	Occurrence: Nonstan. Operations	Emissions Quantity (ppm)	Primary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
SO_2	Coal	Flue gas	X		2800				SO_3	Medium	Low		
									H_2SO_4	Medium	Low	<.001	
									Inorganic sulfates & sulfites	Medium	Low	1-20$_{-3}$ μgm	
	Oil		X		2800	Medium	0.005-0.30	<95					
	Gas				<500								
SO_3	Coal	Flue Gas	X		200				H_2SO_4	Medium	Low		
									Inorganic sulfates & sulfites	Medium	Low	1-20$_{-3}$ μgm	
	Oil		X		200	Low	0.005	<95					
	Gas				<50								

TABLE 3-1. Continued
b. Concluded

Species	Source	Stream	Occurrence		Emissions Quantity (ppm)	Primary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
			Standard Operations	Nonstan. Operations									
H_2SO_4	All sources	Flue gas	X		200	Low	<0.005	<90	Inorganic sulfates	Medium	High		
Metallic sulfates	Coal, Oil		X		Small	High							
H_2SO_3	All		X		200	Low			Inorganic sulfates	Medium	Medium		
COS	All			X	Very small	High	Very small						
H_2S, Organic sulfur compounds, CS_2, thiosulfates	Coal, Oil Gas			X	Very small	Variable	H_2S- 0.001-0.025	H_2S- <50					Upsets: H_2S may be as high as ~2000 ppm for short times

T-187

TABLE 3-1. PRELIMINARY POLLUTANT CATALOG
c. HYDROCARBON COMPOUNDS

T-187

Species	Source	Stream	Occurrence		Emissions Quantity (ppm)	Primary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
			Standard Operations	Nonstan. Operations									
Alkanes	Coal Oil Gas	Flue gas		X X X	<150 <25 <50	Medium			Aldehydes Acids Ketones Alcohols Nitrates Nitrites Peroxyacyl Nitrates	Medium Small Small Small Medium Medium Medium	High High Medium Medium Medium Low Medium	<0.06	
Alkenes	Coal Oil Gas	Flue gas		X X X	<150 <10 <25	Low			Aldehydes Acids Ketones Alcohols Epoxides Peroxides Nitrates Nitrites Peroxyacyl Nitrates Nitrocarboxylic acids	Medium Small Small Small Small Small Medium Medium Medium Small	High High Medium Medium Medium Medium Medium Low Medium Medium	<0.06 <0.05-6 <0.05	
Alkynes	Coal Oil Gas	Flue Gas		X X X	<10 <5 <5	High							
Oxygenated Hydrocarbons													
Aldehydes	Coal Oil Gas	Flue Gas		X X X	<10 5 (utility) 2.5 - 200 (industrial) <5	High			Acids Alcohols Organic aerosol Peroxyacyl nitrates	Medium Small Small Medium	High Medium High Medium		
Carboxylic acids	Coal Oil Gas	Flue Gas		X X X	<200 6-12 <3	High	≤0.08	<10	Organic aerosol Esters	High Small	High Medium		
Ketones	Coal Oil Gas	Flue Gas		X X X		Medium			Acids	Medium	High		

TABLE 3-1. Continued
c. Continued

T-1R7

Species	Source	Stream	Occurrence: Standard Operations	Occurrence: Nonstan. Operations	Emissions Quantity (ppm)	Primary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
Aromatic Hydrocarbons													
Benzene and its Derivatives	Coal	Flue Gas		X	<50	High (Benzene)	<0.03	<20	Phenols	Medium	High		
	Oil				<30	Low (Trialkyl benzenes)			Cresols	Medium	High		
	Gas				<20				Oxygenated compounds (acids, aldehydes, peroxides)	Small	Variable		
									Nitrobenzenes	Small	High		
									Peroxy benzoyl nitrates	Small	Low		
					CONCENTRATIONS IN ppb								
Anthracene	Coal	Flue Gas	X		0.1-0.3 (utility & industrial)	Medium	CONCENTRATIONS (IN µg/m³) 2	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.4-1000 (residential)				Hydroperoxides		Low		
Also napthalene	Oil		X		2	Medium	2		Quinones		Medium		
									Carboxylic acids		Medium		
									Ketones		Low		
									Aldehydes		Low		
	Gas			X			2		Dimers		High		

TABLE 3-1. Continued
c. Continued

T-107

Species	Source	Stream	Occurrence		Emissions Quantity (ppb)	Primary Pollutant Persistence^a	Measured Ambient Concentration (μg/m^3)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence^a	Measured Ambient Concentration (ppm)	Comments
			Standard Operations	Nonstan. Operations									
Phenanthrene	Coal	Flue gas	X		0.01-0.3 (utility)	Medium	0-3	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.3-3 (industrial)				Hydroperoxides		Low		
					9-2300 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X		0.7-3.7				Ketones Aldehydes		Low Low		
	Gas			X	0.04				Dimers		High		
Fluoranthrene	Coal	Flue Gas	X		0.003-0.5 (utility)	Medium	0-3	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.8-10 (industrial)				Hydroperoxides		Low		
					13-350 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X		0.02-1.8				Ketones Aldehydes		Low Low		
	Gas			X	0.04-3.4				Dimers		High		
Pyrene	Coal	Flue Gas	X		0.01-0.5 (utility)	Medium	1-35	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.06-4.5 (industrial)				Hydroperoxides		Low		
					2-2500 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X		0.005-2.2				Ketones Aldehydes		Low Low		
	Gas			X	0.05-7.5				Dimers		High		
Benzo(a)pyrene	Coal	Flue Gas	X		0.003-0.1 (utility)	Medium	5-40	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.007-2.2 (industrial)				Hydroperoxides		Low		
					0.008-800 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X		0.006-.3				Ketones Aldehydes		Low Low		
	Gas			X	0.006-.1				Dimers		High		

TABLE 3-1. Continued
c. Continued

Species	Source	Stream	Occurrence		Emissions Quantity (ppb)	Primary Pollutant Persistence[a]	Measured Ambient Concentration (μg/m³)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
			Standard Operations	Nonstan. Operations									
Benzo-(e)pyrene	Coal	Flue gas	X		0.007-0.15 (utility)	Medium	1-25	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.02-1.7 (industrial)				Hydroperoxides		Low		
					1.0-330 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Gas			X	0.006-.5				Ketones		Low		
									Aldehydes		Low		
									Dimers		High		
Perylene	Coal		X		0.005-0.015 (utility)	Medium	0-1	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.35 (industrial)				Hydroperoxides		Low		
					0.1-770 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
									Ketones		Low		
									Aldehydes		Low		
									Dimers		High		
Anthranthrene	Coal		X		0.001-0.007 (utility)	Medium	1	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.06 (industrial)				Hydroperoxides		Low		
					0.26-100 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Gas			X	.02-.06				Ketones		Low		
									Aldehydes		Low		
									Dimers		High		
Benzo-(ghi)-perylene	Coal		X		0.003-0.22 (utility)	Medium	2-45	<50	Peroxides	Variable (Depending on Environment)	Medium		
					1 (industrial)				Hydroperoxides		Low		
					0.11-440 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X		.08				Ketones		Low		
									Aldehydes		Low		
	Gas			X	.55-.70				Dimers		High		

TABLE 3-1. Continued
c. Concluded

T-187

Species	Source	Stream	Occurrence		Emissions Quantity (ppb)	Primary Pollutant Persistence[a]	Measured Ambient Concentration ($\mu g/m^3$)	% From Combustion Source	Possible Secondary Pollutants	Quantity Formed Relative to Primary Pollutant	Secondary Pollutant Persistence[a]	Measured Ambient Concentration (ppm)	Comments
			Standard Operations	Nonstan. Operations									
Benz-(a) anthracene	Coal	Flue Gas	X			Medium	0-20	<50	Peroxides	Variable (Depending on Environment)	Medium		
									Hydroperoxides		Low		
									Quinones		Medium		
									Carboxylic acids		Medium		
									Ketones		Low		
									Aldehydes		Low		
									Dimers		High		
Chrysene	Coal	Flue Gas	X			Medium			Peroxides	Variable (Depending on Environment)	Medium		
									Hydroperoxides		Low		
									Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X						Ketones		Low		
									Aldehydes		Low		
									Dimers		High		
Coronene	Coal	Flue Gas	X		0.001-0.017 (utility)	Medium	0-20	<50	Peroxides	Variable (Depending on Environment)	Medium		
					0.005-0.06 (industrial)				Hydroperoxides		Low		
					0.22-1.8 (residential)				Quinones		Medium		
									Carboxylic acids		Medium		
	Oil		X		.5				Ketones		Low		
									Aldehydes		Low		
	Gas			X	.004-.85				Dimers		High		

TABLE 3-1. PRELIMINARY POLLUTANT CATALOG
d. TRACE ELEMENTS

Species	Source	Stream	Occurrence		Emissions Quantity[b] (ppm)			Primary Pollutant Persistence[a]	Measured Ambient Concentration ng/m^3	% From Combustion Source	Possible Secondary Pollutants	Comments
			Standard Operations	Nonstan. Operations	Bottom Ash	Flyash	PFG					
TRACE ELEMENTS												
Aluminum	Coal	Flue gas, solid ash	X			<10		High	10-3000	<50		
Antimony								High				
Arsenic								High				
Barium								High	5-20	<50		
Bromine						<10		Medium	10-500	<50		
Cadmium								High				
Calcium								High	2000	<50		
Cerium					<200	<100	<500	High				
Cesium					<5	<5	<100					
Chromium								High	5-20	<50		
Cobalt								High				
Copper								High	10-50	<50		
Dyprosium					<10	<5	<10	High				
Erbium					<1	<1	<5	High				
Europium					<2	<5	<5	High				
Fluorine						<50		High				
Gadolinium					<5	<2	<20	High				
Germanium					<5	<20	<50	High				
Gold					<0.1	<0.1	<5	High				
Hafnium					<10	<10	<10	High				
Holmium					<1	<1	<5	High				
Iodine					←	<0.1	→	Medium	5-10			
Iron								High	1000-5000	<50		
Iridium					<0.1	<0.1	<5	High				
Lanthanum					<50	<50	<100	High				
Lead								High	1000-4000	<20		
Lutetium					<1	<0.1	<5	High				
Magnesium								High	500-3000	<50		
Manganese								High	20-100	<50		
Mercury								Medium				
Molybdenum								High				
Neodymium					<200	<100	<200	High				
Nickel								High	10-100	<50		
Osmium					<20	<0.1	<5	High				
Palladium					<0.1	<0.1	<5	High				
Phosphorus (as Phosphates)					←	<100	→	Medium				
Platinum					<0.1	<0.1	<5	High				
Potassium					<5000	<5000	<10000	High	100-1000	<50		
Praseodymium					<20	<5	<20	High				
Rhenium					<0.1	<0.1	<5	High				
Rubidium					<50	<50	<500	High				
Ruthenium	↓		↓		<0.1	<0.1	<500	High				

TABLE 3-1. Concluded
d. Concluded

Species	Source	Stream	Occurrence		Emissions Quantity (ppm)			Primary Pollutant Persistence[a]	Measured Ambient Concentration ng/m^3	% From Combustion Source	Possible Secondary Pollutants	Comments
			Standard Operations	Nonstan. Operations	Bottom Ash	Flyash	PFG					
Samarium	Coal		X		<2	<5	<5	High				
Scandium					<100	<100	<20	High				
Selenium (as compounds)					←	<0.1	→	Medium				
Silicon						Small		High	1000-8000	<10		
Sodium					<10000	<10000	<10000	High	1000-5000	<50		
Strontium					<15	<10000	5000	High				
Tantalum					<3	<2	<15	High				
Tellurium					<1	<1	<10	High				
Terbium					<0.5	<1	<5	High				
Thalium					<1	<0.5	<5	High				
Tin					<2	<5	<50	High				
Titanium						Small		High	20-400	50		
Tungsten					<20	<50	<50	High				
Vanadium						Small		High	15-100	80		
Ytterbium					<5	<5	<5	High				
Yttrium					<100	<200	<500	High				
Zinc						Small		High	100-500	50		
Zirconium	↓		↓		<100	<200	<200	High				

[a] Persistence: Low — <0.1 day
Medium — 0.1-1.0 day
High — >1.0 day

[b] Emission quantities are presented in three categories; Bottom Ash is all solid material removed ahead of particulate removal devices; Flyash is the ash removed in the electrostatic precipitator or other particulate control device, and PFG is the material which escapes the particulate control device either as fine ash or vapor.

Note that quantities are in ppm by weight of the total material in that category, i.e., cerium is less than 0.05% (500 ppm) of the ash which escapes collection and goes up the stack.

their persistence measured as above, and any known data on their ambient concentrations. These data are principally from the Los Angeles Basin. The reader is reminded that Table 3-1 contains preliminary information and will be added to or condensed during the next year, as additional data become available.

3.2 POLLUTANT EFFECTS RESEARCH METHODOLOGY

A variety of research techniques has been used to evaluate the toxicity of pollutants. The following subsections discuss these techniques and their relevance to the current program; research methods which evaluate human health effects are considered in the first subsection, aquatic and terrestrial effects are considered in the second.

3.2.1 Methods to Assess Ambient Pollutant Health Effects

Research methods which elucidate the toxic effects of inhaled substances have involved:

- Long- and short-term laboratory studies in animals
- Short-term experimental exposures of human volunteers
- Case reports
- Industrial hygiene reports
- Epidemiologic studies of occupationally-exposed workers
- Community epidemiologic studies, involving either the general population or selected subgroups such as children and asthmatics

When the results of such studies are evaluated to estimate ambient exposures which adequately protect the health of the general population, the uncertainties, ranges of applicability, and disadvantages inherent in a particular method must be considered.

Table 3-2 briefly discusses these basic research methods and tabulates their advantages and limitations. The following points should be emphasized:

- While animal study is the only practical method for assessing long-term response to controlled pollutant exposure, extrapolation from animal to human effects is qualitative at best. Animal study is therefore most effective in identifying possible pollutant effects and in generating new hypotheses regarding mechanisms of action rather than in developing quantitative data on exposure thresholds.

T-188

TABLE 3-2. METHODS FOR DETERMINING HEALTH EFFECTS OF AIR POLLUTANTS

Method	Brief Description	Advantages	Limitations
Animal toxicology	• Rats, mice, rabbits, guinea pigs, beagles, cats, and monkeys are often used in animal studies. Typically one group of animals is placed in an exposure chamber to which the pollutant is added at a specified rate and concentration for a selected period of time. A second, identical group of control animals is also placed in an exposure chamber containing filtered air for the same exposure schedule as the experimental group. The animals may inhale the pollutant normally or through a mask, mouthpiece, or intratracheal cannula, or a pneumothorax may be performed. Mortality following exposure may be observed to determine an LD50. The animals may be tested for pulmonary function, increased susceptibility to bacterial infection, morphologic changes in tissue, cells, or cellular components, changes in enzyme activity, or alteration of protein and lipid molecular structure. Animals may also be sacrificed for histo-pathological examination at various selected intervals.	• Easier and less expensive to perform than human studies; results can be obtained fairly rapidly. • Various modes of administration are possible: continuous, intermittent, inhalation, direct intratracheal insufflation, intravenous injection, intrapleural inoculation, pneumothorax. • Nearly unlimited freedom of experimental design; animals can be sacrificed at any time. • Mechanisms of injury can be determined. • Is the only reasonable method for assessing long-term response to controlled pollutant exposure. Small animals, e.g., rats and mice, may be exposed for their natural life-span. • Intraspecies variation in response due to genetic differences can be reduced by use of inbred strains. • A variety of subject types may be exposed: old, young, healthy, with or without preexisting chronic cardiac or respiratory disease or acute respiratory illness. • A larger number of subjects may be exposed in comparison to experimental human exposures. • A wider range of pollutant concentrations and total dosages may be administered (lethal and sublethal doses), hence a maximal dose-response curve can be established.	• Severe limitations (quantitative, qualitative, mechanistic) in extrapolation to human effects. • Subjective information cannot be elicited from the subject. • The degree to which the animal model approximates the human response or disease mechanisms is not known (great interspecies variation). • Use of healthy animals (appropriate human disease models in laboratory animals may not exist) limits the sensitivity of the animal exposure. • Should be relied upon only when human data are insufficient or unavailable. • Is best used for generating new hypotheses regarding mechanisms of action, for identifying new effects not previously observed in humans, for indicating areas in need of further human study.

TABLE 3-2. CONTINUED

Method	Brief Description	Advantages	Limitations
Experimental Human Exposures	• Experimental human studies usually involve measurement of pulmonary function before, during and after air pollutant exposure. Volunteers selected for participation are usually required to give a personal history of such characteristics as allergies, asthma, chronic respiratory or heart disease, smoking habits, etc. A physical examination is given before exposure and baseline measurements of pulmonary function, such metabolic parameters as heart rate, temperature, blood pressure, etc. are recorded. Exposures are usually conducted in an exposure chamber supplied with filtered air plus the pollutant; and exposure conditions (concentration, temperature, humidity, etc.) are rigorously monitored and controlled. Alternatively, exposures may be conducted in a body plethysmograph. Subjects may breathe normally or through a mouthpiece. They may remain at rest or they may exercise intermittently or continuously. During exposures, the investigator may record signs such as coughing, wheezing, etc. and take measurements of various pulmonary parameters. Pulmonary function would again be tested following exposure; subjects would be interviewed for subjective responses or symptoms (e.g., eye irritation, fatigue, throat or nose irritation, etc.), and given a physical examination.	• Extrapolation of results from one species to another is eliminated. • The actual exposure time, pollutant concentration, mode of administration, total respired volume of air, atmospheric conditions (humidity, temperature, etc.) can be precisely controlled. • A single pollutant or any desired combination of pollutants may be accurately administered. • Subjects' characteristics that may influence response can be identified (e.g., age, state of health, preexisting chronic respiratory or cardiac disease, history of asthma or allergy, smoking, etc.); each subject can serve as his own control, thus controlling for many covariates. • Subjective responses can be elicited from volunteers (e.g., substernal soreness, eye or throat irritation, etc.). • Differential effects of exercise, temperature and/or humidity can be observed. • From such studies it is theoretically possible to determine a dose-response curve or to establish a minimal effective dose.	• The study designs possible (in terms of mode of administration, pollutant dose, range of physiological response that can be measured) are limited by considerations of ethics, cost, and time required. • Cost and inconvenience to the subjects involved usually dictate that exposures be brief — several hours to several days; hence, effects of chronic or long-term exposure cannot be observed. • Exposures usually involve less than 10 subjects because of expense and availability of laboratory facilities. • Although some hypersusceptibles have been studied, most human studies have involved "healthy young adult volunteers" — a group unrepresentative of the general population. • Due to the complexity of the pollutant mixture found in ambient air, the actual atmospheric exposure cannot be adequately duplicated in an experimental chamber. • There is some degree of risk to the exposed subjects of discomfort — not of inevitable injury.

TABLE 3-2. CONTINUED

Method	Brief Description	Advantages	Limitations
Experimental Human Exposures (Concluded)	Aside from testing pulmonary function, an investigator may study cardiac or metabolic responses or perform biochemical analyses of blood or urine.		
Reports of Occupational Exposures (Nonepidemiologic and Epidemiologic)	• Several methods of reporting occupational exposures are available; (1) the case history describing a single subject's response to a particular episode (usually accidental exposure to an extremely high concentration of a pollutant); (2) an epidemiologic analysis in which workroom concentrations are estimated or measured and partial medical histories, subjective complaints or physical exams are obtained from the workers exposed in an attempt to relate exposure to present state of health (often exposures and health effects are recorded before and after improvements in workroom practices, ventilation, or control equipment are instigated, allowing comparison of decreased health effects from reduced exposures); (3) retrospective or prospective studies (historical or otherwise) in which a study population is identified and exposures are reconstructed or a study population is selected and followed through time to establish medical and exposure histories.	• It is often possible to observe the effects of exposure to isolated pollutants at concentrations much higher than those likely to occur in ambient air; hence, this is the sole means by which the upper end of a dose-response curve can be established, e.g., SO_2 in ore smelters, NO_x in nitration plant workers, CO_2 in meat packers, etc. • Combination of pollutant exposure plus a work/stress factor is more likely to produce measurable health effects than would exposure regimes of an experimental study. • Where adequate work histories are available, chronic effects of long-term, intermittent exposures may be determined. • Possibility of accurately characterizing the pollutant dose is greater than for a community epidemiologic study, although not as good as an experimental study.	• Much of the data collected is of a subjective nature as workload and workroom procedures usually preclude extensive physical exams. • The study population is usually nonrepresentative of the general population in that workers are predominantly male, 18 to 65 years of age, and sufficiently healthy to be working. • Occupational exposure studies may generally be regarded as inadvertent experiments with only limited control of exposure conditions. • Occupational exposures are not directly comparable with ambient exposures both because industrial workers are a nonrepresentative subgroup of the general population and because an occupational exposure is intermittent (8 to 10 hours per day, 5 days per week) while an ambient exposure is continuous; theoretically, an intermittent exposure is presumed to be less injurious than a continuous exposure of equivalent total dose (concentration x time) because a time period for recovery is present.

TABLE 3-2. CONCLUDED

Method	Brief Description	Advantages	Limitations
Community Epidemiologic Studies	• Several types of epidemiology studies have been performed to evaluate the health effects of air pollutants: (1) a study population is identified and some measurement of health effects (clinical examination, questionnaire, telephone interview, etc.) is compared with concurrent pollutant characterizations for that locality; (2) a study essentially similar to type (1) above but in which health effects and pollutant levels are assessed at intervals for a period of time (a school year, 2 years or longer, weekly for several months, etc.); (3) selected mortality or morbidity rates for a given area are compared with the pollutant characterization for that area on a yearly, monthly, weekly, etc. basis and an attempt is made to establish statistical correlations between air pollution factors and morbidity or mortality. The study population can involve the community-at-large, children, the elderly, susceptible groups such as asthmatics, nonsmokers, etc. Health parameters observed have included eye irritation, subjective complaints, pulmonary function, acute respiratory illness prevalence and incidence, mortality rates from lung cancer and other pulmonary or cardiac causes.	• Study group is experiencing a real life exposure (as opposed to artificial exposures encountered in experimental studies). • Exposure over longer periods of time (months-to-years) can be studied. • Hypersusceptible individuals are inevitably included. • Currently only means known to study chronic low-level exposure in humans.	• Can only establish a statistical association; potentially causal relationships can be indicated but not easily established. • Inconsistency in reporting exposure data (annual maximum, daily maxima, annual mean, hourly averages, etc.) makes interpretation of various studies difficult. • Extremely difficult to characterize actual ambient atmospheres due to complexity of pollutant mixtures; hence, it is difficult to associate any health effect with a single pollutant. • Exposures of all individuals in the community are characterized by a few monitoring stations. Micrometerology of community may result in large variations in actual exposure levels. • Big indoor/outdoor differences in exposure levels are known to exist, but have not been allowed for in studies to date. • To identify statistical strengths of various pollutants or atmospheric conditions that may influence the health effect studied, the investigator must assume that there is no synergism or antagonism between variables and that the relationship between each variable and the health effect is linear. • The establishment of experimental groups and proper controls is difficult. Exposed populations have a flux of subjects in and out. • Results over currently available time periods (~1 to 10 years) may be obscured by other effects.

- Experimental human exposures must be short; hence, potential effects of long-term continuous exposure to a particular substance must be inferred from results of short-term human exposures and long-term animal studies.
- Although the community epidemiologic study involves a real life exposure over a period of time (weeks-to-years), there are great difficulties both in characterizing the ambient pollutant mixture and in defining the actual exposure of individual members of the study population. Therefore, associating any single pollutant with a particular health effect is difficult, and must rely on related evidence from studies of animal or human (experimental and occupational) exposures.

Since the data base available on health effects of pollutant exposure (i.e., long-term, low-level exposure) is limited, identification of an ambient concentration at which a particular health effect may be expected to occur is not possible. Conversely, it would be equally difficult to attempt an identification of pollutant levels from which no adverse health effect would be expected. Indeed, for many substances considered in this report, the published literature contains no accounts of human or animal exposures at levels that approximate, even within several orders of magnitude, ambient concentrations typical of community exposures.

Lack of suitable data presents great difficulties in situations requiring use of an ambient pollutant level to indicate when attention should be given to possible health effects from continuous, long-term exposure. Consequently, a method for estimating permissible ambient concentrations for community exposure using occupational threshold limit values (TLVs) and LD50s (the dose that is lethal to 50 percent of the experimental animal population) from animal toxicologic work has been suggested for comparison by Research Triangle Institute (RTI) (Reference 3-6).

However, there are obvious limitations to direct analogies between occupational exposures or animal LD50s and continuous exposure of the general population. Occupational TLVs were originally designed to protect most (95 percent) of the exposed working force. But these TLVs may not necessarily be the same as the threshold limits for an entire community. Occupational exposure is intermittent (8 hours per day, 5 days per week, 50 or less weeks per year), whereas community exposure is continuous. For the same total dose (concentration x time) an intermittent exposure is generally assumed to be less harmful than continuous exposure, because intermittent exposure allows a period for recovery.* This differential toxicity allows the occupational standard to specify a larger total dose than may be acceptable for a community exposure.

---

*There are several substances which are exceptions to this assumption; some degree of immunity may be developed during a continuous exposure. Hence, symptoms of toxicity may be more severe during an intermittent exposure.

In addition, an occupational TLV is designed for a group of people that does not represent the general population. The industrial working force likely to be exposed to a potentially toxic substance is generally male, 19 to 65 years of age, and medically fit to be working; this subgroup excludes many women, the aged, persons not fit enough to work, and infants and children. Children and infants particularly are considered to be hypersusceptible, on a body weight basis, to some inhaled substances. These differences in population characteristics and exposure time constrain analogies between occupational TLVs and permissible community exposures.

Using LD50 values to estimate ambient levels for continuous exposure is subject to the limitations inherent in any animal study, primarily difficulties in quantitative extrapolation from animal to human effects. Furthermore, there are many uncertainties involving the degree to which the animal tested approximates the human response or disease mechanism. Therefore, there is no exact proportional relationship between animal LD50s and human no-effect levels for all pollutants.

Acknowledging these difficulties, RTI (Reference 3-6) has developed a formula, based on TLV and LD50 data, to estimate the concentration of a pollutant or pollutant mixture to which the general public may be continuously exposed without hazard to health. This concentration was defined by RTI as "the pollutant concentration ($\mu g/m^3$) for which continuous exposure with 100 percent absorption causes a stationary maximum body concentration equal to 0.05 percent of LD50 value of the compound, assuming a biological half-life of 30 days" (Reference 3-6, page 36). From analyses of present TLV standards, RTI reasoned that a stationary maximum body burden of 0.05 percent of the oral LD50 value for rats can be considered safe.

Linear regression analyses of the relationship between TLVs and LD50 values were performed. This was unsuccessful (correlation coefficient of 0.61 for 191 substances; correlation coefficient of 0.70 when 50 agricultural chemicals were added); however, it was pointed out that a poor correlation was not surprising, considering the wide range of TLVs for a given LD50 value. The basic relationship of TLV to LD50 was then compared with derived numerical relationships which describe pollutant uptake, excretion, and accumulation on a body weight and respiratory frequency basis. From these comparisons, equations were derived to estimate permissible ambient exposures incorporating a number of assumptions and safety factors. Two of these equations are used in the present report to estimate pollutant concentrations for continuous exposure: (1) $x = 1.65 \times 10^{-3}$ (TLV), and (2) $x = 4.77 \times 10^{-5}$ (LD50), where x is the permissible ambient concentration and LD50 is the oral LD50 for rats.

RTI emphasizes that these estimated concentrations, x, are not applicable to known or suspected mutagens, carcinogens, or teratogens, and are applicable only to substances whose biological half-life is short compared to the assumed life of the individual. In addition, these formulae, based upon a "one-compartment model with a single, first-order excretion rate," do not take account of synergistic actions between two or more pollutants, and assume: (1) that all pollutants entering the respiratory system are retained by the body, and (2) that animal LD50 values are applicable to man (Reference 3-6). Other assumptions and safety factors incorporated into calculation of permissible concentrations include:

1. The inhaled pollutant is evenly distributed throughout the body
2. The absorption factor equals 1; i.e., all of the inhaled pollutant is absorbed
3. The rate of excretion is proportional to the body concentration of the pollutant
4. The biological half-life of pollutants in the body is 30 days
5. A safety factor of 40/168 is applied to TLVs in converting intermittent to continuous exposure episodes on a weekly basis
6. A safety factor of 0.5 is introduced to insure protection of infants and children, since one-year-old infants have approximately twice the respiratory frequency of an adult
7. Based on present TLV standards, a body burden of 0.05 percent (0.0005) of the oral LD50 for rats can be considered safe for continuous exposure

The primary weakness of RTI's work is the many assumptions made, even though simplifying assumptions are necessary if a single expression is to predict safety levels for a wide variety of pollutants. Assumptions concerning biological half-lives were made to insure the greatest degree of safety (e.g., many inhaled substances have half-lives in man of much less than 30 days, Tables 4 and 5 in Reference 3-6). Assumptions concerning rates of excretion, age differences in respiratory uptake, and corrections for the weekly, intermittent nature of occupational exposures are also reasonable. However, assumptions of 100 percent absorption rates, even distribution of inhaled pollutants throughout the body, and the applicability of animal LD50 data to man may limit the usefulness of these calculations. The estimates also do not consider the irritant or disease-producing effects of inhaled substances that are retained in the lungs and not absorbed, or the selective concentration of absorbed substances in particular organs or tissues. Furthermore, for many substances the extent to which the animal model approximates the human response is not known; therefore the validity of the RTI model in such a situation is not known.

In Table 1 of their report, RTI compares their estimates for continuous exposure with preexisting ambient standards. The results indicate that RTI's estimates are usually conservative, but best applied to indicate orders of magnitude rather than specific concentration levels.

In spite of its limitations, the RTI model is extensively used in this report to estimate ambient pollutant levels below which adverse health effects from continuous exposure would be unlikely to occur. It is a reasonable model in situations where insufficient or no toxicologic, occupational, or epidemiologic evidence concerning health effects of chronic exposure is available. However, for this report three additional limitations must be considered.

One limitation is that compensating safety factors for some hypersusceptible portions of the general population are not incorporated into the model. This group includes asthmatics, persons with chronic obstructive pulmonary disease such as chronic bronchitis and emphysema, and persons with other pulmonary or cardiac insufficiencies.

A second limitation is that many pollutants exhibit significant temporal variations in ambient concentration, because of source characteristics, meteorology, or atmospheric reactions. The model developed by RTI estimates a concentration for continuous exposure and does not consider fluctuations in ambient concentration. As ambient pollutant levels fluctuate, it may be necessary to consider acute as well as chronic effects of exposure. For some pollutants, short-term exposures produce effects that are unlike those observed during long-term exposure. For example, nitrogen dioxide exposure for short periods (several hours to several days) at near-ambient levels produces irritation to the lung and reversible lesions in the pulmonary tissue. However, there is some evidence that continuous exposure for several years or more at near-ambient levels of nitrogen dioxide may cause emphysema in experimental animals. It is possible that a maximum permissible concentration for continuous exposure based on observed acute effects (the effects reflected in many LD50 values), may not adequately protect the exposed population from effects that may result from long-term exposure.

For substances for which a demonstrated difference between acute and chronic effects exists and which exhibit fluctuations in ambient levels (due either to diurnal patterns of emissions and atmospheric reactions or due to occasional air pollution episodes), several permissible ambient concentrations may have to be stipulated. One concentration would protect against chronic effects by continuous exposure, while a second concentration would protect against acute effects. For example, both EPA's Office of Air Quality Planning and Standards (OAQPS) and the Congress are currently evaluating the need for a short-term NO_2 ambient air standard to supplement the current standard based on annual averages.

A third limitation to the RTI model is that when two or more substances are present in the inhaled air, their interaction may produce additive, antagonistic or synergistic effects. The possibility of synergistic or potentiating interaction between two pollutants has significant implications for the exposed population. When two truly synergistic substances are simultaneously inhaled, for example an irritant gas (SO_2) and particulate aerosols, the toxicological response is a greater degree of irritation or decrease in pulmonary function than would be expected if the irritant effects of each substance, taken separately, had simply been added. Therefore, to estimate maximum concentrations for continuous exposure, the simultaneous presence of two synergistic pollutants would require lower maximum concentrations for each than would be necessary if either substance were present alone.

Unfortunately there is little quantitative information available on pollutant synergisms. The degree of potentiating effect, such as that suspected to occur between SO_2 and particulates, can be highly variable depending upon species tested, ambient temperature, humidity, and specific physicochemical type and size of particulate used. Since these interactions are highly individual, there is no general formula for estimating maximum concentrations for continuous exposure which could incorporate a safety margin to accommodate such interactions. Synergism as defined above is entirely different from a defined chemical reaction in the atmosphere between two individual pollutants which produces a new chemical species of greater toxicity; for example, the well known reaction between atmospheric ozone or other photochemical oxidants and sulfur dioxide which produces the more irritant sulfur trioxide/sulfuric acid/acid sulfate continuum.

The limitations discussed above must be carefully considered in evaluating the preliminary screening concentrations presented in Section 3.3. Again it should be emphasized that these levels are intended to provide order-of-magnitude guidance on pollutant toxicity, not exact exposure levels.

3.2.2 Methods of Assessing Pollutant Impacts on Biota

Principal techniques for evaluating impacts of pollutants on terrestrial and aquatic biota are identified, described, and briefly critiqued in Table 3-3. Three levels of evaluation are addressed:

- "First Estimate" Techniques. This includes methods for making a rapid (and preliminary) assessment of the potential for a specific chemical or class of chemicals, at known concentrations, to adversely affect aquatic or terrestrial biota. Methods include reviewing reports and other publications which summarize known concentrations at which specific chemicals produce damage.

TABLE 3-3. METHODS OF ASSESSING POLLUTANT IMPACTS UPON AQUATIC AND TERRESTRIAL SYSTEMS
PART A. "FIRST ESTIMATE" TECHNIQUES

Method	Description	Comments on Suitability
Literature/Information Survey	Generalized, broad literature review to identify known environmental significance of a pollutant class or particular chemical species. Information for review includes all summary documents and publications/reports describing the following: • Distribution and levels of pollutant(s) in compartments of the environment • Sources of the pollutant(s) • Pathways available for pollutant transport into these compartments • Potential toxic, bioaccumulation, and synergistic effects • Kinetics of pollutant accumulation in biotic tissues • Transformation products that may be of environmental importance •	State of the art. Useful for rapidly screening for potential biotic impacts of various pollutant concentrations. Values expressed in literature are not usually reliable for site-specific situations, but such values are often useful for identifying whether or not specific studies should be undertaken.
Bioassay Results Review	Review of results of specific bioassay and environmental physiology experiments that have assessed impacts of the specific pollutants of interest, upon various species.	State of the art. Useful for rapidly obtaining experimentally-derived data on acute effects of pollutants on biota. Normally, there are limitations for direct use in site-specific circumstances because of potential chemical/physical interactive phenomena that will likely occur at a specific site.
Modeling of Permissible Concentrations	Based upon LD50 data and other information from the literature. A derivation of pollutant hazard criteria for a particular situation, which specifies safe or permissible concentrations for various pollutants of interest. Comparison of these derived concentrations with concentration levels anticipated for a particular source.	Theoretical. Has been used in a preliminary way as described in EPA report EPA-600/2-76-155 (Reference 3-6), but must be field and laboratory tested before it will be of general applicability.
National Monitoring Networks	Widely distributed networks of sampling stations where physical, chemical, and biological samples are routinely collected for analysis are a part of the U.S. Water Pollution Surveillance System, which includes STORET retrieval. Other surveillance networks monitoring air chemistry, pesticide, and other chemicals in soils, water, and vegetation.	State of the art. Such networks generally monitor ambient conditions and trends and compare values to standards and guidelines so enforcement or other corrective actions can be rapidly taken. In the process, huge quantities of data on ambient chemical concentrations in various substrata are obtained, organized, and stored in computer-retrievable fashion, available for use by the public. The magnitudes of the various national network monitoring programs make their data useful for an initial screening of potential pollution problems caused by incremental additions from contemplated action.

TABLE 3-3. METHODS OF ASSESSING POLLUTANT IMPACTS UPON AQUATIC AND TERRESTRIAL SYSTEMS
PART B. EXPERIMENTAL ESTABLISHMENT OF IMPACT CONCENTRATIONS

Method	Description	Comments on Suitability
Short-term Static	Standard tests to determine the concentration level of a pollutant which will kill 50 percent of the experimental subjects during a specific exposure period (the LC_{50}, or lethal concentration for 50 percent of the individuals). Toxicity curves are constructed from experimental results to allow mortality predicting at various concentrations and exposure times and determination of toxicity thresholds. It is important to recognize that a wide variety of special bioassy techniques and associated hypotheses are used.	State of the art. Is routinely employed to test toxicity of chemicals; the bulk of information which would be available for individuals taking the approaches identified in Part A has come from this method. LC_{50} concentrations are obviously well above the level where impacts on organisms could initially occur. Must be applied to a great many species and at all life stages for data to have widespread utility, and must be interpreted with cognizance that effects other than death (such as altered reproduction and survivorship) can be very important to individuals, populations, and ecosystems. Such acute tests do not account for these sublethal effects. Moreover, toxicities differ with water quality and other conditions.
Chronic Bioassy	Standard tests to determine the effects of long term exposure to a chemical on growth, reproduction, survival, avoidance behavior, swimming performance, etc. Continuous monitoring of physiological and behavioral responses, such as blood physiology, locomotion, feeding activity, breathing rate (opercular movement), etc. permits detection of responses to pollutants at stressing concentrations far below concentrations which result in death. Chronic tests are employed to help estimate long-term safe concentrations.	State of the art. Although not as widely "proven" or accepted as short-term (acute) tests, is becoming increasingly important. As with acute bioassay results, one must be careful in extrapolating results from toxicity experiments on one population of a species to other populations of the species inhabiting different environments. Because chronic bioassays require such long experimental periods, it has been customary to estimate long-term safe concentrations by using acute bioassays in combination with application factor derivations.
Fumigation Experiments	Standard tests to determine the concentration levels of gaseous pollutants which will cause chlorosis, necrosis, or other visible symptoms of damage to terrestrial plants. Single pollutants or mixtures of different pollutants can be introduced into the fumigation chambers to test interactive phenomena. Histological and/or physiological examinations can be made of experimental subjects to detect nonvisible responses to pollutants.	State of the art. Results are not readily extrapolatable from area to area, since changes in relative humidity, soil moisture, temperature, etc. influence the susceptibility of plant individuals to airborne pollutants. Fumigation experiments are being conducted to a lesser extent on animals as well.
Bioaccumulation Experiments	Tests to determine transfer and accumulation of chemicals in different ecosystem compartments (e.g., substrate to producers to primary consumers to secondary consumers to tertiary consumers) through monitoring the concentration of a known quantity of a chemical introduced into the test medium, in various links in a single food chain.	Experimental. Such tests have not been widely employed. They are useful in identifying indicator species which magnify the substance of interest, so that their indicators can be utilized in site-specific field situations to biomonitor pollution levels.

TABLE 3-3. METHODS OF ASSESSING POLLUTANT IMPACTS UPON AQUATIC AND TERRESTRIAL SYSTEMS
PART C. SITE-SPECIFIC TECHNIQUES

T-189

Method	Description	Comments on Suitability
Elemental and Compound Analyses	Analyze air, water, and soil media, and tissues or whole organisms of selected species by screening methods (spark source mass spectrometry, atomic fluorescence spectrophotometry, anodic voltametry, etc.), and element or compound-specific methods (atomic absorption spectroscopy, flameless atomic absorption spectrophotometry, thin-layer and gas chromatography, etc.), to determine levels of various pollutants in abiotic and biotic compartments of the site ecosystem. Compare values with those in literature to determine potential problems.	State of the art.
Effluent Bioassay	Conduct controlled, long-term bioassays in situ or using mobile laboratories stationed close to effluent location, to determine effects of effluent on aquatic organisms selected for their known susceptibility to pollutants at specific concentrations. Generally, all life stages of the test organism are tested.	State of the art. This methodology is expected to become much more widely used by agencies and industry in the future.
Monitoring Biological System State Variables	Long term monitoring of community species composition, population density, biomass, species diversity index, ponderal index, etc. in "treatment" and "control" areas within the site area of interest, to detect changes which might be caused by pollution stress. Indicator species are often monitored.	State of the art. Generally, natural "background noise" of these variables makes the resolution of data collected for this purpose too low to draw meaningful cause-effect conclusions. Simultaneous monitoring of chemical concentrations should be conducted and the experimental design, including sampling intensity, must be very well-defined.
Quantification of Foliar Damage	In treatment and control plots, examination of the foliage of plant species known to be particularly sensitive to pollution damage, to measure and quantify the extent of bleaching, chlorosis, necrosis, stippling, or other symptoms associated with ambient pollution levels. Simultaneous monitoring of yields in both plots is commonly performed.	State of the art. Definitive cause-effect relationships are sometimes difficult, but can be achieved if treatment and control plots are on soils of comparable moisture, nutrient, temperature, etc. Also, ground-level pollutant concentrations should be continuously monitored at the control and treatment plot locations.
Open-Top Chambers	Determinations of impacts of ambient pollution conditions as evidenced by foliar markings and yield of sensitive or economically important plant species using experimental test chambers that effectuate control over variables that undoubtedly complicate results of routine foliar damage quantification approaches. Experimental and control chambers can be located side by side, with ambient levels permitted to reach the chamber plants in the treatment chamber, and with the pollutant filtered out of the "control" chamber.	Experimental. Being tested in some parts of the United States. Should have wide-spread applicability to site-specific determinations of terrestrial damage by pollutants.

TABLE 3-3. Concluded
PART C. Concluded

Method	Description	Comments on Suitability
Stress Determinations by Color Imagery	Use of color and color infrared aerial imagery in conjunction with ground-truthing to identify stress signatures and to determine extent and intensity of pollution damage to crop and woodland species.	Experimental to state of the art. Permits rapid assessment of major pollution damage to vegetation in vicinity of operational facility. Can also serve to identify areas of vegetation stress over broad regions.
Monitoring Physiological Processes	Measurement of stress caused by pollutants can potentially be conducted by collecting test subjects living in treatment and control sites and examining them for abnormal physiological function. General adaptation syndrome, immune response, biochemical reactions, and other physiological processes are thought to provide stress signatures of sufficiently high resolution so as to document chronic stress damage long before demographic changes or shifts in species composition will be evidenced from pollution challenge.	Theoretical and experimental. Warrants considerable future effort, because of the presumed sensitivity and resolution of such a monitoring approach. Is presently being investigated at site of coal-fired electric generating station in Montana. Use of fish respirometers (etc.) to detect stress should be considered state of the art. Methodology, in broadest application, can be applied to plants as well, through measurement of formation, translocation, action of auxins, or water stress, susceptibility to nutrient stress, etc.
Monitoring Histological Characters	Approach and rationale similar to that described for physiological, but applied to lung tissue, adrenal glands, gills, etc.	Experimental and state of the art. Has considerable promise for detecting chronic damage in aquatic and terrestrial organisms.
Indicator Species	Monitoring abundance, biomass, distribution, behavior, etc. of species known to react in predictable ways to pollutants.	State of the art.
Modeling	Use of ecosystem level models to describe and predict effects of pollution challenge; to segregate pollutant effects from natural variations occurring within the site ecosystem.	Theoretical and in early experimental phases. Requires extensive information input from all ecosystem compartments so, until perfected, will be costly and time-consuming.

Also, included under "First Estimate" techniques are broad, national monitoring networks which maintain periodic surveillance on levels of certain chemicals in various substrata. Concentration values resulting from such networks can identify locations where pollution levels exceed permissible standards and where more detailed investigation of effects is necessary.

- Experimental Establishment of Impact Concentrations. Included herein are methods appropriate for experimentally establishing the concentrations at which specific chemicals will cause lethal or sublethal damage in sensitive species of aquatic and terrestrial biota. Results from these tests should be sufficiently general that they could be used in the general information base and in publications and reports for future screening.
- Site-Specific Techniques. These are methods to ascertain whether pollutants at a particular site have affected local aquatic and terrestrial ecosystems, or species within the ecosystems

All extant techniques are limited. For example, most approaches that have been used to test a specific chemical have failed to evaluate interactive phenomena such as synergistic, additive, or antagonistic behaviors of associated chemicals in the effluent stream, as they relate to effects on organisms. Potential ecotypic differences in tolerances to chemicals by populations of a species in different areas remain unexplored. Assumptions that closely-related taxa have similar chemical tolerances to taxa used in test situations are questionable, yet are usually necessary because of the extremely limited number of different species which have been investigated for pollution tolerance. Pollutant effects on different life stages of a species are often overlooked and sublethal effects are largely undetermined. Effects of alternative culturing times/techniques on susceptibility of test organisms and the capability of natural (and cultured) populations to acquire resistance to particular pollutants in general remain unexplored. Because of these and many other limitations of available methods, conventional experimental techniques often yield data which have little value in assigning "safe" or permissible levels of toxicant emissions.

Moreover, certain site-specific techniques are rather crude and cannot incorporate the controls necessary to establish causative relationships when damage is noted. Because of these and other problems, data generated from the techniques identified in Table 3-3 are limited in utility. However, the acceleration of toxicant testing programs which incorporate subroutines to segregate some of these problems will result in better data.

100

The current effort used only the very general first estimate procedures to set the limits indicated in Section 3.3; these limits will be further refined as the program progresses. Much basic data on the incremental effects of NO_x controls on the biota will be collected in the bioassay testing to be conducted in the future under this program.

3.3 CONCENTRATION ESTIMATES FOR SCREENING COMBUSTION RELATED POLLUTANTS

Using the methods described previously (and recognizing the limitations of these methods), preliminary screening concentrations were generated for those pollutants from Table 3-1 for which the supporting information could be obtained or estimated. These results are presented in Table 3-4 for human health effects and in Table 3-5 for effects on terrestrial and aquatic biota. These data will be used elsewhere in this report (Section 7) for preliminary screening and priority setting. The data presented herein will be reviewed under both the impact assessment and test data collection tasks of the NO_x environmental assessment program. The results will be revised, whenever new information requires. The presentation of only the calculated levels herein does not reflect the large volume of data on health effects which has been collected and reviewed.

The concentration values presented in Table 3-4 (except when an ambient air standard existed and could be used instead) were generated according to the RTI method presented in Section 3.2. The levels to be used for screening were generated from the occupational threshold limit value (whenever one existed for the species) by the equation

$$x = 1.65 \cdot 10^{-8} \text{ (TLV)}$$

using the 8-hour time-weighted average (TWA) TLV. In cases where a TLV was unavailable, concentrations were estimated from LD50s by the equation

$$x = 4.77 \cdot 10^{-5} \text{ (LD50)}$$

Oral LD50 values for rats were preferred, followed by oral LD50 data for mice, and intraperitoneal and subcutaneous LD50s. In a few cases, TDLo (lowest published toxic dose) and LDLo (lowest published lethal dose) were used.

Although the RTI formulae have been discussed previously, it should be repeated that these estimates are, at best, a rough approximation. Rather than the specific concentration derived from these calculations, the general order of magnitude (1 ppm, 10^{-1} ppm, 10^{-2} ppm, etc.) should be regarded as the result of such estimation. Two comments made in Section 3.2 should be considered carefully in making use of the results in Table 3-4.

TABLE 3-4. ESTIMATION OF CONCENTRATIONS FOR SCREENING COMBUSTION-GENERATED POLLUTANTS

Substance	Recommended Occupational TLV NIOSH (Ref. 3-7) 8-hr TWA ppm (mg/m^3)	 ACGIH (Ref. 3-8) 8-hr TWA ppm (mg/m^3)	 ACGIH (Ref. 3-8) 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
ORGANICS						
methane	b	b	b	-	Non-toxic within range of estimated emissions.	-
ethane	b	b	b	-	Non-toxic within range of estimated emissions.	-
propane	b	b	b	-	Non-toxic within range of estimated emissions.	-
n-butane	b	600 (1,400)	750 (1,610)	0.97 (2.31)	$x = 1.65 \times 10^{-3}$ (1400).	3-6
ethylene	b	b	b	-	Non-toxic within range of estimated emissions.	-
propylene	b	b	b	-	Non-toxic within range of estimated emissions.	-
butylene	b	b	b	-	Non-toxic within range of estimated emissions.	-
1,3-butadiene	b	1,000 (2,200)	1,250 (2,750)	1.64 (3.63)	$x = 1.65 \times 10^{-3}$ (2200).	3-6
acetylene	2,500 (2,662)	b	b	-	NIOSH recommended TLV based on flammability; non-toxic within range of estimated emission.	-
methyl acetylene	b	1,000 (1,650)	1,250 (2,060)	1.65 (2.72)	$x = 1.65 \times 10^{-3}$ (1650).	3-6
cyclohexane	b	300 (1,050)	375 (1,300)	0.50 (1.73)	$x = 1.65 \times 10^{-3}$ (1050).	3-6
cyclohexene	b	300 (1,015)	300 (1,015)	0.49 (1.67)	$x = 1.65 \times 10^{-3}$ (1015).	3-6
formaldedehyde	b	2 (3)	2 (3)	0.004 (0.005)	$x = 1.65 \times 10^{-3}$ (3).	3-6
acetaldehyde	b	100 (180)	150 (270)	0.17 (0.28)	$x = 1.65 \times 10^{-3}$ (180).	3-6
butyraldehyde	b	b	b	(0.04) (0.12)	Oral LD50, rat: 2490 mg/kg; $x = 4.77 \times 10^{-5}$ (2490).	3-6, 3-9
crotonaldehyde	b	2 (6)	6 (18)	0.00 (0.01)	$x = 1.65 \times 10^{-3}$ (6).	3-6
acrolein	b	0.1 (0.25)	0.3 (0.75)	0.165 ppb (0.412 µg/m^3)	$x = 1.65 \times 10^{-3}$ (0.25)	3-6
acetone	b	1,000 (2,400)	1,250 (3,000)	1.67 (3.96)	$x = 1.65 \times 10^{-3}$ (2400).	3-6
methyl ethyl ketone	b	200 (590)	250 (740)	0.33 (0.97)	$x = 1.65 \times 10^{-3}$ (590).	3-6
cyclohexanone	b	50 (200)	50 (200)	0.08 (0.33)	$x = 1.65 \times 10^{-3}$ (200).	3-6

TABLE 3-4. Continued

Substance	Recommended Occupational TLV NIOSH 8-hr TWA ppm (mg/m^3)	 ACGIH 8-hr TWA ppm (mg/m^3)	 ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
ORGANICS						
methanol	200 (262)	200 (260)	250 (310)	0.33 (0.43)	$x = 1.65 \times 10^{-3}$ (262).	3-6
ethanol	b	1,000 (1,900)	1,000 (1,900)	1.67 (3.14)	$x = 1.65 \times 10^{-3}$ (1900).	3-6
propanol	b	200 (500)	250 (625)	0.34 (0.83)	$x = 1.65 \times 10^{-3}$ (500).	3-6
ethylene glycol-vapor	b	100 (260)	125 (325)	0.16 (0.43)	$x = 1.65 \times 10^{-3}$ (260).	3-6
particulate	b	- (10)	- (20)	- (0.02)	$x = 1.65 \times 10^{-3}$ (10).	3-6
dimethyl ether	b	b	b	-	Non-toxic within estimated range of emissions.	-
diethyl ether	b	400 (1,200)	500 (1,500)	0.65 (1.98)	$x = 1.65 \times 10^{-3}$ (1200).	3-6
ethylene oxide	b	50 (90)	75 (135)	0.08 (0.15)	$x = 1.65 \times 10^{-3}$ (90).	3-6
formic acid	b	5 (9)	5 (9)	0.008 (0.01)	$x = 1.65 \times 10^{-3}$ (9).	3-6
acetic acid	b	10 (25)	15 (37)	0.02 (0.04)	$x = 1.65 \times 10^{-3}$ (25).	3-6
propionic acid	b	b	b	- (0.07)	Oral LD50, rat: 1510 mg/kg $x = 4.77 \times 10^{-5}$ (1510).	3-6, 3-9
formates:						
ethyl formate	b	100 (300)	150 (450)	0.16 (0.49)	$x = 1.65 \times 10^{-3}$ (300).	3-6
methyl formate	b	100 (250)	150 (375)	0.16 (0.41)	$x = 1.65 \times 10^{-3}$ (250).	3-6
acetates:						
ethyl acetate	b	400 (1,400)	400 (1,400)	0.64 (2.31)	$x = 1.65 \times 10^{-3}$ (1400).	3-6
methyl acetate	b	200 (610)	250 (760)	0.33 (1.01)	$x = 1.65 \times 10^{-3}$ (610).	3-6
n-propyl acetate	b	200 (840)	250 (1,050)	0.33 (1.39)	$x = 1.65 \times 10^{-3}$ (840).	3-6
isopropyl acetate	b	250 (950)	310 (1,185)	0.38 (1.57)	$x = 1.65 \times 10^{-3}$ (950).	3-6
n-butyl acetate	b	150 (710)	200 (950)	0.25 (1.17)	$x = 1.65 \times 10^{-3}$ (710).	3-6
sec-butyl acetate	b	200 (950)	250 (1,190)	0.33 (1.57)	$x = 1.65 \times 10^{-3}$ (950).	3-6
tert-butyl acetate	b	200 (950)	250 (1,190)	0.33 (1.57)	$x = 1.65 \times 10^{-3}$ (950).	3-6

TABLE 3-4. Continued

Substance	Recommended Occupational TLV			Estimated Conc.	Justification for Estimate	References
	NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	ppm (mg/m^3)		
ORGANICS						
isobutyl acetate	b	150 (700)	187 (875)	0.24 (1.16)	$x = 1.65 \times 10^{-3}$ (700).	3-6
propionates:						
methyl propionate	b	b	b	0.03 (0.12)	Oral LDLo, rabbit: 2550 mg/kg; $x = 4.77 \times 10^{-5}$ (2550).	3-6, 3-9
ethyl propionate	b	b	b	0.04 (0.17)	Oral LD50, rat: 3500 mg/kg $x = 4.77 \times 10^{-5}$ (3500).	3-6, 3-9
acetic anhydride	b	5 (20)	5 (20)	0.01 (0.03)	$x = 1.65 \times 10^{-3}$ (20).	3-6
maleic anhydride	b	0.25 (1)	0.25 (1)	0.0004 (0.002)	$x = 1.65 \times 10^{-3}$ (1).	3-6
succinic anhydride	b	b	b	- (0.124)	Subcutaneous TDLo, rat: 2600 mg/kg/65 weeks; $x = 4.77 \times 10^{-5}$ (2600).	3-6, 3-9
peroxyacetic acid	b	b	b	- (0.073)	Oral LD50, rat: 1540 mg/kg $x = 4.77 \times 10^{-5}$ (1540).	3-6, 3-9
benzene	1 (3.2) (See ref. 3-11)	10 (32)	25 (80)	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10, 3-11
toluene	100 (375) 8-hr TWA 200 (750) 10-min. ceiling	100 (375)	150 (560)	0.16 (0.62)	$x = 1.65 \times 10^{-3}$ (375).	3-6
ethyl benzene	b	100 (435)	125 (545)	0.16 (0.72)	$x = 1.65 \times 10^{-3}$ (435).	3-6
cumene	b	50 (245)	75 (365)	0.08 (0.4)	$x = 1.65 \times 10^{-3}$ (245).	3-6
styrene	b	100 (420)	125 (525)	0.16 (0.69)	$x = 1.65 \times 10^{-3}$ (420).	3-6
cresol	b	5 (22)	5 (22)	0.01 (0.04)	$x = 1.65 \times 10^{-3}$ (22).	3-6
vinyl-toluene	b	100 (480)	150 (720)	0.16 (0.79)	$x = 1.65 \times 10^{-3}$ (480).	3-6
p-t-butyl toluene	b	10 (60)	20 (120)	0.02 (0.1)	$x = 1.65 \times 10^{-3}$ (60).	3-6

TABLE 3-4. Continued

	Recommended Occupational TLV					
Substance	NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
ORGANICS						
nitroaniline	b	1 (6)	2 (12)	0.002 (0.01)	x = 1.65 x 10^{-3} (6).	3-6
naphthalene	b	10 (50)	15 (75)	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
biphenyl	b	0.2 (1)	0.2 (1)	0.0003 (0.002)	x = 1.65 x 10^{-3} (1).	3-6
PCB's (as chlorodiphenyl)						
42% chlorine	b	- (1)	- (1)	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
54% chlorine	b	- (0.5)	- (0.5)	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
anthracene	b	b	b	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
phenanthrene	b	b	b	- (0.03)	Oral LD50, mice: 700 mg/kg x = 4.77 x 10^{-5} (700).	3-6, 3-9
fluoranthene	b	b	b	- (0.09)	Oral LD50, rat: 2000 mg/kg x = 4.77 x 10^{-5} (2000)	3-6, 3-9
pyrene	b	b	b	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
benzo(a)-pyrene	b	b	b	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
benzo(e)-pyrene	b	b	b	- (1ng/m^3)	Suspected carcinogen.	3-6, 3-10
perylene	b	b	b	- (1ng/m^3)	By analogy with naphthalene.	
anthanthrene	b	b	b	-	Insufficient toxicologic information to estimate an exposure.	
benzo(ghi)-perylene	b	b	b	-	Insufficient toxicologic information to estimate an exposure.	
coronene	b	b	b	-	Insufficient toxicologic information to estimate an exposure.	

TABLE 3-4. Continued

Substance	NAAQS (Ref. 3-12)	Recommended Occupational TLV					
	Conc. ppm (mg/m^3)	NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
GASES AND PARTICULATES							
carbonates							
ammonium carbonate	a	b	b	b	- (0.004)	Intravenous LD 50, mice: 96 mg/kg; $x = 4.77 \times 10^{-5}$ (96)	3-6, 3-9
ammonium bicarbonate	a	b	b	b	- (0.012)	Intravenous LD 50, mice: 245 mg/kg; $x = 4.77 \times 10^{-5}$ (245)	3-6, 3-9
potassium carbonate	a	b	b	b	- (0.09)	Oral LD 50, rat: 1870 mg/kg; $x = 4.77 \times 10^{-5}$ (1870)	3-6, 3-9
carbonyls							
nickel carbonyl	a	b	0.05 (0.35)	0.05 (0.35)	- (1 ng/m^3)	Suspected carcinogen.	3-6, 3-10
iron pentacarbonyl	a	b	0.01 (0.08)	0.01 (0.08)	0.02 ppb (0.0001)	$x = 1.65 \times 10^{-3}$ (0.08)	3-6
carbon (elemental)	a	b	- (3.5)	- (7)	- (0.006)	$x = 1.65 \times 10^{-3}$ (3.5)	3-6
carbides							
calcium carbide	a	b	b	b		By analogy to calcium hydroxide, calcium carbide is non-toxic within range of estimated emissions.	
iron carbide	a	b	- (1)	- (2)	- (0.002)	TLV for soluble iron salts; $x = 1.65 \times 10^{-3}$ (1)	3-6
silicon carbide	a	b	- (10)	- (20)	- (0.02)	TLV for nuisance particulates; $x = 1.65 \times 10^{-3}$ (10)	3-6
tungsten carbide	a	b	- (5)	- (10)	- (0.008)	TLV for insoluble tungsten compounds; $x = 1.65 \times 10^{-3}$ (5)	3-6
nitric acid	a	2 (5)	2 (5)	4 (10)	0.003 (0.008)	$x = 1.65 \times 10^{-3}$ (5)	3-6
nitrates	a	b	b	b	- (0.008)	By analogy to nitric acid.	
nitrites	a	b	b	b	- (0.008)	By analogy to nitric acid.	
cyanides							
hydrogen cyanide	a	b	10 (11)	15 (16)	0.016 (0.018)	$x = 1.65 \times 10^{-3}$ (11)	3-6
metallic cyanides	a	b	b	b	0.016 -	By analogy to hydrogen cyanide.	
ammonia	a	50	25 (18)	35 (27)	0.06 (0.04)	$x = 1.65 \times 10^{-3}$ (25)	3-6
cyanates	a	b	b	b	0.016 -	By analogy to hydrogen cyanide.	

T-190

TABLE 3-4. Continued

Substance	NAAQS Conc. ppm (mg/m^3)	Recommended Occupational TLV NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
GASES AND PARTICULATES							
amines, imines, imides							
methylamine	a	b	10 (12)	10 (12)	0.015 (0.020)	$x = 1.65 \times 10^{-3}$ (12)	3-6
ethylamine	a	b	10 (18)	10 (18)	0.016 (0.030)	$x = 1.65 \times 10^{-3}$ (18)	3-6
ethylenediamine	a	b	10 (25)	10 (25)	0.017 (0.041)	$x = 1.65 \times 10^{-3}$ (25)	3-6
diethylamine	a	b	25 (75)	25 (75)	0.041 (0.124)	$x = 1.65 \times 10^{-3}$ (75)	3-6
cyclohexylamine	a	b	10 (40)	10 (40)	0.016 (0.066)	$x = 1.65 \times 10^{-3}$ (40)	3-6
aniline	a	b	5 (19)	5 (19)	0.008 (0.031)	$x = 1.65 \times 10^{-3}$ (19)	3-6
nitriles	a	b	b	b	0.016 -	By analogy to hydrogen cyanide.	3-6
nitro compounds							
nitromethane	a	b	100 (250)	150 (375)	0.165 (0.412)	$x = 1.65 \times 10^{-3}$ (250)	3-6
2-nitropropane	a	b	25 (90)	25 (90)	0.041 (0.148)	$x = 1.65 \times 10^{-3}$ (90)	3-6
nitrobenzene	a	b	1 (5)	2 (10)	1.65 ppb (8.25 ug/m^3)	$x = 1.65 \times 10^{-3}$ (5)	3-6
amides							
acetamide	a	b	b	b	- (1 ug/m^3)	Suspected carcinogen.	3-10
formamide	a	b	20 (30)	30 (45)	0.033 (0.050)	$x = 1.65 \times 10^{-3}$ (30)	3-6, 3-9
azo compounds							
azobenzene	a	b	b	b	- (1 ng/m^3)	Suspected carcinogen.	3-10
azoxy compounds							
azoxybenzene	a	b	b	b	- (1 ng/m^3)	Suspected carcinogen.	3-10
sulfuric acid	a	- (1)	- (1)	- (1)	- (0.002)	$x = 1.65 \times 10^{-3}$ (1)	3-6
ammonium sulfate	a	b	b	b	- (0.003)	Oral LD 50, rat: 58 mg/kg; $x = 4.77 \times 10^{-5}$ (58)	3-6, 3-9
metallic sulfates	a	b	b	b	- (0.002)	By analogy to sulfuric acid.	

107

TABLE 3-4. Continued

	NAAQS	Recommended Occupational TLV					
Substance	Conc. ppm (mg/m^3)	NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
GASES AND PARTICULATES							
sulfurous acid	a	b	b	b	- (0.027)	By analogy to sulfur dioxide, with allowance for differences in molecular weight.	
metallic sulfites	a	b	b	b	- (0.027)	By analogy to sulfur dioxide, with allowance for differences in molecular weight.	
sulfides							
carbon disulfide	a	b	20 (60)	30 (90)	0.032 (0.099)	$x = 1.65 \times 10^{-3}$ (60)	3-6
hydrogen sulfide	a	b	10 (15)	15 (27)	0.016 (0.025)	$x = 1.65 \times 10^{-3}$ (15)	3-6
carbonyl sulfide	a	b	b	b	0.016 (0.041)	By analogy to hydrogen sulfide.	
metallic thiosulfates							
calcium thiosulfate	a	b	b	b	- (0.027)	Intraperitoneal LDLo, rat: 573 mg/kg; $x = 4.77 \times 10^{-5}$ (573)	3-6, 3-9
magnesium thiosulfate	a	b	b	b	- (0.038)	Intraperitoneal LDLo, rat: 805 mg/kg; $x = 4.77 \times 10^{-5}$ (805)	3-6, 3-9
elemental sulfur	a	b	- (10)	b	- (0.016)	TLV for nuisance dusts; $x = 1.65 \times 10^{-3}$ (10)	3-6
mercaptans							
ethyl mercaptan	a	b	0.5 (1)	0.5 (1)	0.0008 (0.0016)	$x = 1.65 \times 10^{-3}$ (1)	3-6
sulfoxides							
methyl sulfoxide	a	b	b	b	- (0.001)	Oral LD 50, rat: 20mg/kg; $x = 4.77 \times 10^{-5}$ (20)	3-6, 3-9
thiocyanates							
ammonium thiocyanate	a	b	b	b	- (0.024)	Intraperitoneal LDLo, mice: 500 mg/kg $x = 4.77 \times 10^{-5}$ (500)	3-6, 3-9
potassium thiocyanate	a	b	b	b	- (0.041)	Oral LD 50, rat: 854 mg/kg; $x = 4.77 \times 10^{-5}$ (854)	3-6, 3-9
sodium thiocyanate	a	b	b	b	- (0.036)	Oral LD 50, rat: 764 mg/kg; $x = 4.77 \times 10^{-5}$ (764)	3-6, 3-9
sulfur dioxide	0.03 (0.08) annual arithmetic mean	2 (5)	5 (13)	5 (13)	0.03 (0.08)	Annual arithmetic mean, federal air quality standard.	3-12
	0.14 (0.365) 24-hour annual maximum				0.14 (0.365)	24-hour maximum not to be exceeded more than once per year, federal air quality standard.	3-12

TABLE 3-4. Continued

	NAAQS	Recommended Occupational TLV					
Substance	Conc. ppm (mg/m^3)	NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
GASES AND PARTICULATES							
sulfur trioxide	a	b	b	b	- (0.002)	By analogy to sulfuric acid	
carbon monoxide	9 (10) 8-hour annual maximum	35 (38)	50 (55)	400 (440)	9 10	8-hour maximum, not to be exceeded more than once per year, federal ambient air standard.	3-12
	35 (40) 1-hour annual maximum	200 (ceiling) (220)			35 (40)	1-hour maximum, not to be exceeded more than once per year, federal ambient air standard.	3-12
nitric oxide	a	25 (30)	25 (30)	35 (45)	0.04 (0.05)	$x = 1.65 \times 10^{-3}$ (30)	3-6
nitrogen dioxide	0.05 (0.1) annual arithmetic mean	1 (1.8)	5 (9)	5 (9)	0.05 (0.1)	Annual arithmetic mean, federal ambient air standard.	3-12
carbon dioxide	a	10,000 (18,000)	5,000 (9,000)	15,000 (18,000)	8.25 (14.85)	$x = 1.65 \times 10^{-3}$ (9,000)	3-6
		30,000 ceiling (54,000)					
phosphorus pentoxide	a	b	b	b	- (0.002)	By analogy with phosphoric acid; (TLV Of 1 mg/m^3); $x = 1.65 \times 10^{-3}$(1)	3-6
phosphorous sesquioxide	a	b	b	b	- (0.0002)	By analogy with P_2O_5; P_4O_6 is approximately 10 times more toxic.	
elemental oxygen	a	b	b	b		Non-toxic within estimated range of emissions.	
ozone	0.08 (0.16) 1-hour annual maximum	b	0.1 (0.2)	0.3 (0.6)	0.08 (0.16)	Annual 1-hour maximum, not to be exceeded more than once per year; NAAQS for photochemical oxidants.	3-12
metallic phosphates	a	b	b	b		Non-toxic within estimated range of emissions.	
metallic hydrides	a	b	b	b		Non-toxic within estimated range of emissions.	
elemental hydrogen	a	b	b	b		Non-toxic within estimated range of emissions.	
selenium compounds	a	b	- (0.2)	- (0.2)	- (0.0003)	$x = 1.65 \times 10^{-3}$ (.2); (as Se)	3-6
hydrogen chloride	a	b	5 (7)	5 (7)	0.008 (0.012)	$x = 1.65 \times 10^{-3}$ (7)	3-6
potassium chloride	a	b	b	b	- (0.12)	Intraperitoneal LDLo, rat: 2430 mg/kg; $x = 4.77 \times 10^{-5}$ (2430)	3-6, 3-9
sodium chloride	a	b	b	b	- (0.14)	Oral LD 50, rat: 3000 mg/kg; $x = 4.77 \times 10^{-5}$ (3000)	3-6, 3-9

TABLE 3-4. Continued

	NAAQS	Recommended Occupational TLV					
Substance	Conc. ppm (mg/m^3)	NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
GASES AND PARTICULATES							
hydrogen bromide	a	b	3 (10)	3 (10)	0.005 (0.016)	$x = 1.65 \times 10^{-3}$ (10)	3-6
potassium bromide	a	b	b	b	0.0002 (0.001)	By analogy with bromide (TLV of 0.1 ppm, $0.7 mg/m^3$); $x = 1.65 \times 10^{-3}$ (0.7)	3-6
sodium bromide	a	b	b	b	- (0.167)	Oral LD 50, rat: 3500 mg/kg; $x = 4.77 \times 10^{-5}$ (3500)	3-6, 3-9
hydorgen fluoride	a	b	3 (2)	3 (2)	0.005 (0.003)	$x = 1.65 \times 10^{-3}$ (2)	3-6
potassium fluoride	a	b	b	b	- (0.012)	Oral LD 50, rat: 245 mg/kg; $x = 4.77 \times 10^{-5}$ (245)	3-6, 3-9
sodium fluoride	a	b	b	b	- (0.009)	Oral LD 50, rat: 180 mg/kg; $x = 4.77 \times 10^{-5}$ (180)	3-6, 3-9
hydrogen iodide	a	b	b	b	0.005 (0.016)	By analogy with hydrogen bromide.	
potassium iodide	a	b	b	b	- (0.089)	Oral LDLo, mice: 1862; $x = 4.77 \times 10^{-5}$ (1862)	3-6, 3-9
sodium iodide	a	b	b	b	- (0.207)	Oral LD 50, rat: 4340 mg/kg; $x = 4.77 \times 10^{-5}$ (4340)	3-6, 3-9
total hydrocarbons	0.24 (0.16) 3-hour (6-9am) annual maximum	b	b	b		NAAQS for hydrocarbons selected for achievement of NAAQS for photochemical oxidants, health effects not observed at these levels.	3-13
total particulate	- (0.26) 24-hour annual maximum	b	b	b	- (0.26)	24-hour maximum, not to be exceeded more than once per year, federal ambient air standard.	3-12
	- (0.075) 1-year geometric mean				- (0.075)	Annual geometric mean, federal ambient air standard.	3-12

TABLE 3-4. Continued

Substance	Recommended Occupational TLV: ACGIH 8-hr TWA (mg/m^3)	Recommended Occupational TLV: ACGIH 15 min STEL (mg/m^3)	Estimated Conc. (mg/m^3)	Justification for Estimate	References
ELEMENTS					
aluminum (as Al_2O_3)	10	10	0.0165	TLV for nuisance dusts: x = 1 65 x 10^{-3} (10).	3-6
antimony compounds (as Sb_2)	0.5	0.75	0.825 ug/m^3	x = 1.65 x 10^{-3} (0.5).	3-6
arsenic	0.5	0.5	0.825 ug/m^3	x = 1.65 x 10^{-3} (0.5).	3-6
barium, soluble compounds	0.5	0.5	0.825 ug/m^3	x = 1.65 x 10^{-3} (0.5).	3-6
beryllium	0.002	0.025	3.3 ng/m^3	x = 1.65 x 10^{-3} (0.002).	3-6
bismuth	b	b	0.016	Based on TLV for bismuth telluride; x = 1.65 x 10^{-3} (10).	3-6, 3-8
boron oxide	10	20	0.0165	x = 1.65 x 10^{-3} (10).	3-6
cadmium					
oxide fume, as Cd	0.05	0.05	82.5 ng/m^3	x = 1.65 x 10^{-3} (0.05)	3-6
salts, as Cd	0.05	0.15	82.5 ng/m^3	x = 1.65 x 10^{-3} (0.05).	3-6
calcium oxide	5	5	0.00825	x = 1.65 x 10^{-3} (5).	3-6
cerium	b	b	0.0026	Member of lanthanide series: by analogy to yttrium with corrections for difference in atomic weight.	
cesium	b	b	0.0033	Based on TLV for cesium hydroxide; x = 1.65 x 10^{-3} (2).	3-6, 3-8
chromium	b	b			
insoluble forms			1 ng/m^3	Suspected carcinogen.	3-6
chromic acid and chromates, as CrO_3	0.1	0.1	0.165 ug/m^3	x = 1.65 x 10^{-3} (0.1)	3-6
soluble salts, as Cr	0.5	0.5	0.825 ug/m^3	x = 1 65 x 10^{-3} (0.5).	3-6
cobalt	0.1	0.1	0.165 ug/m^3	x = 1 65 x 10^{-3} (0.1).	3-6
copper	1	2	1.65 ug/m^3	x = 1.65 x 10^{-3} (1).	3-6
dysprosium	b	b	0.003	Member of lanthanide series; by analogy to yttrium with corrections for difference in atomic weight.	

TABLE 3-4. Continued

Substance	Recommended Occupational TLV ACGIH 8-hr TWA (mg/m^3)	 ACGIH 15-min STEL (mg/m^3)	Estimated Conc. (mg/m^3)	Justification for Estimate	References
ELEMENTS					
erbium	b	b	0.0031	Member of lanthanide series;by analogy to yttrium with correction for difference in atomic weight.	
europium	b	b	0.0028	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
gadolinium	b	b	0.0029	Member of lanthanide series by analogy to yttrium with correction for difference in atomic weight.	
gallium	b	b	0.0052	Subcutaneous LDLo, rat· 110 mg/kg; $x = 4.77 \times 10^{-5}$ (110).	3-6, 3-9
germanium	b	b	0.001	Based on TLV for germanium tetrahydride; $x = 1.65 \times 10^{-3}$ (0.6).	3-6, 3-8
gold	b	b	-	Non-toxic within range of estimated emissions.	
hafnium	0.5	1.5	0.0008	$x = 1.65 \times 10^{-3}$ (0.5).	3-6
holmium	b	b	0.003	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
iridium	b	b	3.2 ng/m^3	Member of platinum group; by analogy to platinum with correction for difference in atomic weight.	
iron oxide	5	10	0.00825	$x = 1.65 \times 10^{-3}$ (5).	3-6
iron soluble salts, as Fe	1	2	1.65 ug/m^3	$x = 1.65 \times 10^{-3}$ (1)	3-6
lanthanum	b	b	0.0026	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
lead arsenate, as Pb	0.15	0.45	0.2475 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.15)	3-6
lead, inorganic, as Pb	0.15	0.45	0.2475 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.15).	3-6
lithium	b	b	0.017	Intraperitoneal LDLo, rat: 360 mg/kg; $x = 4.77 \times 10^{-5}$ (360).	3-6, 3-9
lutetium	b	b	0.0032	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
manganese and compounds, as Mn	5	5	0.00825	$x = 1.65 \times 10^{-3}$ (5)	3-6
magnesium oxide fume	10	10	0.0165	$x = 1.65 \times 10^{-3}$ (10).	3-6

TABLE 3-4. Continued

	Recommended Occupational TLV				
Substance	**ACGIH 8-hr TWA (mg/m^3)**	**ACGIH 15-min STEL (mg/m^3)**	**Estimated Conc. (mg/m^3)**	**Justification for Estimate**	**References**
ELEMENTS					
mercury					
all forms, as Hg	0.05	0.15	82.5 ng/m^3	$x = 1.65 \times 10^{-3}$ (0.05)	3-6
alkyl compounds, as Hg	0.01	0.03	16.5 ng/m^3	$x = 1.65 \times 10^{-3}$ (0.01)	3-6
molybdenum, as Mo					
insoluble compounds	10	20	0.0165	$x = 1.65 \times 10^{-3}$ (10)	3-6
soluble compounds	5	10	0.00825	$x = 1.65 \times 10^{-3}$ (5)	3-6
neodymium	b	b	0.0027	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
nickel, soluble compounds, as Ni	0.1	0.3	0.165 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.1).	3-6
niobium	b	b	0.143	Oral LD50, rat, for potassium niobate: 3000 mg/kg; $x = 4.77 \times 10^{-5}$ (3000).	3-6, 3-9
osmium	0.002	0.006	3.3 ng/m^3	Based on TLV for osmium tetroxide, as Os; $x = 1.65 \times 10^{-3}$ (0.002).	3-6
palladium	b	b	1.8 ng/m^3	Member of platinum group; by analogy to platinum with correction for difference in atomic weight.	
platinum	0.002	0.002	3.3 ng/m^3	Based on TLV for platinum salts, as Pt; $x = 1.65 \times 10^{-3}$ (0.002).	3-6
potassium	b	b	-	Non-toxic within estimated range of emissions.	
praseodymium	b	b	0.0026	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
rhenium	b	b	0.013	Intraperitoneal LD50, mice, for rhenium trichloride: 280 mg/kg; $x = 4.77 \times 10^{-5}$ (280).	3-6, 3-9
rhodium	0.1	0.3	0.165 ng/m^3	$x = 1.65 \times 10^{-3}$ (0.1).	3-6
rubidium	b	b	0.21	By analogy to lithium with correction for difference in atomic weight.	
ruthenium	b	b	1.7 ng/m^3	Member of platinum group; by analogy to platinum with correction for difference in atomic weight.	
samarium	b	b	0.0028	Member of lanthanide series, by analogy to yttrium with correction for difference in atomic weight.	
scandium	b	b	0.191	Oral LD50, mice, for scandium trichloride: 4000 mg/kg; $x = 4.77 \times 10^{-5}$ (4000).	3-6, 3-9
selenium compounds, as Se	0.2	0.2	0.33 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.2).	3-6

113

TABLE 3-4. Continued

Substance	Recommended Occupational TLV: ACGIH 8-hr TWA (mg/m^3)	Recommended Occupational TLV: ACGIH 15-min STEL (mg/m^3)	Estimated Conc. (mg/m^3)	Justification for Estimate	References
ELEMENTS					
silicon	10	20	0.0165	TLV for nuisance particulates; $x = 1.65 \times 10^{-3}$ (10).	3-6
silver and soluble compounds, as Ag	0.01	0.03	16.5 ng/m^3	$x = 1.65 \times 10^{-3}$ (0.01).	3-6
sodium	b	b	-	Non-toxic within estimated range of emissions.	
strontium	b	b	0.0433	Intraperitoneal LD50, mice, for strontium chloride: 908 mg/kg; $x = 4.77 \times 10^{-5}$ (908).	3-6, 3-9
tantalum	5	10	0.008	$x = 1.65 \times 10^{-3}$ (5).	3-6
tellurium	0.1	0.1	0.165 ng/m^3	$x = 1.65 \times 10^{-3}$ (0.1).	3-6
terbium	b	b	0.0029	Member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight.	
thallium	0.1	0.1	0.165 $\mu g/m^3$	TLV for soluble thallium salts (as Tl); $x = 1.65 \times 10^{-3}$ (0.1).	3-6
thorium	b	b	1 $\mu g/m^3$	Radioactive, suspected carcinogen.	3-6, 3-10
thulium	b	b	0.0031	Member of lanthanide series; by analogy to to yttrium with correction for difference in atomic weight.	
tin	2	4	0.0033	TLV for inorganic tin compounds (as Sn); $x = 1.65 \times 10^{-3}$ (2)	3-6
titanium, as titanium dioxide	10	20	0.0165	TLV for nuisance particulates; $x = 1.65 \times 10^{-3}$ (10)	3-6
tungsten					
insoluble	5	10	0.0082	$x = 1.65 \times 10^{-3}$ (5)	3-6
soluble	1	3	0.0016	$x = 1.65 \times 10^{-3}$ (1)	3-6
uranium compounds, as U	0.2	0.6	0.33 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.2)	3-6
vanadium oxide, as V					
dust	0.5	1.5	0.825 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.5)	3-6
fume	0.05	0.05	82.5 ug/m^3	$x = 1.65 \times 10^{-3}$ (0.05)	3-6
ytterbium	b	b	0.0032	member of lanthanide series; by analogy to yttrium with correction for difference in atomic weight	
yttrium	1	3	0.0016	$x = 1.65 \times 10^{-3}$ (1)	3-6
zinc chloride fume	1	2	1.65 ug/m^3	$x = 1.65 \times 10^{-3}$ (1)	3-6
zinc oxide fume	5	10	0.00825	$x = 1.65 \times 10^{-3}$ (5)	3-6
zirconium	5	10	0.0082	TLV for zirconium compounds (as Zr); $x = 1.65 \times 10^{-3}$ (5)	3-6

TABLE 3-4. Continued

Substance	Recommended Occupational TLV NIOSH 8-hr TWA ppm (mg/m^3)	ACGIH 8-hr TWA ppm (mg/m^3)	ACGIH 15-min STEL ppm (mg/m^3)	Estimated Conc. ppm (mg/m^3)	Justification for Estimate	References
MISCELLANEOUS SECONDARY POLLUTANTS						
peroxyacetyl-nitrate	b	b	b	0.08 -	Annual 1-hour maximum, not to be exceeded more than once per year; NAAQS for photochemical oxidants.	3-12
nitrocarboxylic acids						
m-nitrobenzoic acid	b	b	b	- (0.032)	Intraperitoneal LD50, rat: 670 mg/kg; $x = 4.77 \times 10^{-5}$ (670)..	3-6, 3-9
p-nitrobenzoic acid	b	b	b	- (0.093)	Oral LD50, rat: 1960 mg/kg; $x = 4.77 \times 10^{-5}$ (1960).	3-6, 3-9
cyclic aldehydes						
fufural	b	5 (20)	15 (60)	0.008 (0.033)	$x = 1.65 \times 10^{-3}$ (20)	3-6
phenol	b	5 (19)	10 (38)	0.008 (0.031)	$x = 1.65 \times 10^{-3}$ (19)	3-6
dicarboxylic acids						
oxalic acid	b	- (1)	- (2)	- (0.0016)	$x = 1.65 \times 10^{-3}$ (1)	3-6
malonic acid	b	b	b	- (0.062)	Oral LD50, rat: 1310 mg/kg; $x = 4.77 \times 10^{-5}$ (1310).	3-6, 3-9
nitrobenzene	b	1 (5)	2 (10)	- (0.008)	$x = 1.65 \times 10^{-3}$ (5)	3-6
hydroperoxides						
t-butyl hydroperoxide	b	b	b	- (0.019)	Oral LD50, rat: 406 mg/kg; $x = 4.77 \times 10^{-5}$ (406).	3-6, 3-9
hydrogen peroxide	b	1 (1.4)	2 (2.8)	0.0016 (0.0023)	$x = 1.65 \times 10^{-3}$ (1.4)	3-6
quinone	b	0.1 (0.4)	0.3 (0.1)	0.00016 (0.00066)	$x = 1.65 \times 10^{-3}$ (0.4)	3-6
carbonaceous particulate matter	b	b	b	- (0.016)	TLV for nuisance dusts; $x = 1.65 \times 10^{-3}$ (10).	3-6
nitrosamines	b	b	b	- 1 ug/m^3	Suspected carcinogens.	3-6, 3-10

TABLE 3-4. Concluded

T-190

Footnotes

a	a National Ambient Air Quality Standard does not exist for this substance
b	an occupational standard does not exist for this substance

Abbreviations

LDLo	lowest published lethal dose
NAAQS	National Ambient Air Quality Standard
STEL	short-term exposure limit
TLV	threshold limit value
TWA	time-weighted average
x	maximum permissible concentration for continuous exposure

TABLE 3-5. ENVIRONMENTAL SIGNIFICANCE OF SOME CHEMICALS THAT MAY EXIST IN AIRBORNE, LIQUID, AND SOLID EFFLUENTS FROM STATIONARY COMBUSTION SOURCES
PART A. CARBON AND NONMETALLIC COMPOUNDS 1/

Element or Chemical Class	Toxic Levels 2/ Aquatic 3/ (ppm)	Toxic Levels 2/ Terrestrial 4/ (mg/kg) 5/	Synergistic Potential or Other Interaction	Index of Bioaccumulation Potential	Index of Biological Impact Potential 6/ Aquatic	Index of Biological Impact Potential 6/ Terrestrial	U.S. Occupational Standards (mg/m³)	References
Paraffins (alkanes)	10-100	658	Photo-oxidation with NO_x yields some PAN	4	4	4	658 mg/kg	3-14,15
Olefins (alkenes)	10-100	42	Ozonated hexene causes plant damage When irradiated, causes plant damage	4	4	4	4	3-14,16,17
Alkynes		8	4	4	4	4	8 mg/kg	3-14
Cyclic Aliphatics	<1	8	4	1	1	1	77 mg/kg	3-14
Aldehydes	1-10	13.8	Synergistic with NO_x and irradiation in causing plant damage	4	4	4	13.8 ppm	3-14,18,19
Carboxylic Acids	0.7	0.2	4	4	4	4	0.2 mg/kg	3-14,20
Single Ring Aromatics	1-10	12	Synergistic with NO_x and irradiation in causing plant damage	4	4	4	12	3-14,18
Polynuclear Aromatics	1.02-2.0	10	Synergistic with ferric oxide	4	4	4	700	3-14,19,21
Carbonates	33	7	Buffering action and affect on pH may contribute to toxicity of high pH	4	4	4		3-14,19,20
Carbonyls	10-100	8	4	4	4	4	7 mg/kg	3-14
Carbon		440	4	4	4	4	3.5 mg/kg	3-14
Nitrates	10-100	10-20 ppb	4	4	4	4		3-14
Nitrites	0.05	1	4	4	4	4	10 ppm	3-14,20,22
Ammonium Compounds	1-10	20 ppm	Ammonia increases rate of SO_2 oxidation	4	4	4		3-14,19,23
Organic N Compounds								
cyanates	0.1	0.5 ppm	4	4	4	4	140	3-14,20
amines	0.08	265	Quaternary amines extract metal cyanides from highly alkaline solutions	4	4	4	10 ppm	3-14,20,24
nitriles	2	7	4	4	4	4	0.05 ppm	3-14,19
nitro compounds		7	Nitrosation of water soluble pesticides under acidic conditions increases variety of N-nitroso compounds Formation of nitrosamines enhanced by thio-cyanate ion	4	4	4	2	3-14,18,25

TABLE 3-5(a). CONCLUDED

Element or Chemical Class	Toxic Levels 2/ Aquatic 3/ (ppm)	Toxic Levels 2/ Terrestrial 4/ (mg/kg) 5/	Synergistic Potential or Other Interaction	Index of Bioaccumulation Potential	Index of Biological Impact Potential 6/ Aquatic	Index of Biological Impact Potential 6/ Terrestrial	U.S. Occupational Standards (mg/m³)	References
imines		14	4	4	4	4		3-19
amides		125	4	4	4	4		3-14
imides	0.1		4	4	4	4		3-20
azo compounds		18	4	4	4	4		3-14
azoxy compounds		4	4	4	4	4		3-14
Sulfates	6.25	20	4	4	4	4	1	3-14,20
Sulfites	203	3 ppm	4	4	4	4	5 ppm	3-14,20
Sulfides		<40 ppm	4	4	4	4	20 ppm	3-14,18
Sulfur		48 ppm	4	4	4	4	1 ppm	3-14,26
Organic S Compounds								
mercaptans		15 mg/m^3	4	4	4	4	800 mg	3-14
sulfoxides		8	4	4	4	4		3-14
thiocyanates		5	4	4	4	4		3-14
Oxides	3.6	0.5-0.7 ppm	Sulfur dioxide synergistic with NO_2 at 0.5-2.5 ppb	4	4	4	0.2	3-14,22,27,28
Oxygen	1	1 ppm	Ozone synergistic with SO_2 Ozone synergistic with PAN	4	4	4	200	3-14,22,29
Halides		0.10 ppm	4	3	1	1	0.1 ppm	3-14,18,30,31

TABLE 3-5. ENVIRONMENTAL SIGNIFICANCE OF SOME CHEMICALS THAT MAY EXIST IN AIRBORNE, LIQUID, AND SOLID EFFLUENTS FROM STATIONARY COMBUSTION SOURCES
PART B. METALLIC INORGANIC COMPOUNDS 1/

Element or Chemical Class	Toxic Levels 2/ Aquatic 3/ (ppm)	Toxic Levels 2/ Terrestrial 4/ (mg/kg) 5/	Synergistic Potential or Other Interaction	Index of Bioaccumulation Potential	Index of Biological Impact Potential 6/ Aquatic	Index of Biological Impact Potential 6/ Terrestrial	U.S. Occupational Standards (mg/m³)	References
Aluminum	0.320	1 ppm	Toxicity of Al complexes is pH dependent	3	2	3	4.6	3-14,16,32
Antimony	10-100	2	4	4	4	4	0.5	3-14
Arsenic	0.520	1.4	4	2	1	1	1	3-14,19
Beryllium	0.15	10	Toxicity decreases with increasing water hardness	4	1	1	2 u/m^3	3-14,19,30
Bismuth		150	4	3	2	2		3-16
Cadmium	0.0026	2	Concentration factor greatest at low salinity Synergistic with Cu and Zn	2	1	2	2	3-14,16,19, 33
Calcium	0.5-10	5	Ca in water reduces compounds of Pb, Zn, and Al Ca requirement is less if Mg concentration is high High K concentration increases tolerance for high Ca concentration	3	3	3		3-14,16,19, 32
Cerium	0.14	4	4	3	2	3		3-14,16,19
Cesium		100	K in water has a slight depressing effect on Cs toxicity Concentration in clams varied inversely as log function of estuary salinity	3	4	3		3-14,16,19
Chromium	0.016	1	2mg chromium/l intensified plant injury caused by nickel	3	2	3	1	3-14,16,19, 20,34
Copper	1-10	2	Cu, Cd, and Zn exert synergistic effects Toxicity decreases with increasing water hardness	4	1	1	1	3-14,30,33, 35,36
Dysprosium		196	4	4	4	4		3-14
Erbium		30	4	4	4	4		3-14
Europium		156	4	4	4	4		3-14
Gadolinium		25	4	4	4	4		3-14
Gallium		37	4	3	4	4		3-14,34
Germanium	1.5	586	4	3	4	4		3-14,17,34

T-191

TABLE 3-5(b). CONTINUED

Element or Chemical Class	Toxic Levels 2/ Aquatic 3/ (ppm)	Toxic Levels 2/ Terrestrial 4/ (mg/kg) 5/	Synergistic Potential or Other Interaction	Index of Bioaccumulation Potential	Index of Biological Impact Potential 6/ Aquatic	Index of Biological Impact Potential 6/ Terrestrial	U.S. Occupational Standards (mg/m³)	References
Gold	0.40	30	4	4	2	3		3-14,16,19
Hafnium	0.06	75	4	4	2	3	0.5	3-14,16
Holmium		270	4	4	4	4		3-14
Iridium			4	4	4	4		
Iron	0.2	7	4	3	2	3		3-14,16,19
Lanthanum	0.15	3.5	4	3	2	3		3-14,16,19
Lead	0.01-1.0	42	Pb toxicity reduced in hard water	2	1	3	150 µ/m^3	3-14,16,19, 37
Lithium		22 mg/m^3	Efflux of Na and Ca in cyanide abolished by replacing Ca with Mg and Na with Li	3	3	3		3-14,16,19
Lutetium		161	4	4	4	4		3-14
Magnesium	50	14	Mg reduces excessive Zn uptake	4	3	3	4.1	3-16,19,25
Manganese	0.2-0.5	0.5	$MnCl_2.4H_2O$ less toxic at low salinities With decreasing salinity the concentration factor of Mn increases Mn injury in plants intensified by Mo & NO_3 Mn reduces severity of Co poisoning in tomatoes NH_4NO_3 reduces toxicity to plants Mn antagonistic to toxic action of Ni	4	3	3	5	3-14,16,19
Mercury	0.0034	2	The toxic effects of mercuric salts are accentuated by the presence of trace amounts of Cu In varying concentrations NaCl exhibits first a synergistic effect, then an antagonistic effect toward the toxicity of $HgCl_2$ Synergistic effects found in all 2 and 3 factor combinations of $HgCl_2$, $Pb(NO_3)_2$, and $ZnSO_4$ Hg with anionic detergents is more than additively toxic Hg more toxic at low salinities	1	1	1	0.1	3-14,16,19, 32

TABLE 3-5(b). CONTINUED

Element or Chemical Class	Toxic Levels 2/ Aquatic 3/ (ppm)	Toxic Levels 2/ Terrestrial 4/ (mg/kg) 5/	Synergistic Potential or Other Interaction	Index of Bioaccumulation Potential	Index of Biological Impact Potential 6/ Aquatic	Index of Biological Impact Potential 6/ Terrestrial	U.S. Occupational Standards (mg/m³)	References
Neodymium		17 μg/kg	4	4	4	3		3-14
Nickel	0.07	.5	Ni more toxic at higher salinities Cu/Ni and Cr/Cu/Ni antagonistic Cr/Ni synergistic	4	1	2	1	3-14,16,19,32
Niobium		130	4	4	4	3		3-14
Osmium	0.1	4	4	4	4	2	2 μg/m³	3-14
Palladium		19	4	4	4	2		3-14
Platinum	0.014	0.9 μg/kg	4	4	1	1	4.6 μ/m³	3-14
Potassium	3.0	6	Excessive K increases tolerance for high concentrations of Ca and Mg Toxicity of K to fish reduced by Ca K in saline irrigation water prevents intake of excessive amounts of NaCl Increase in K decreases herbicidal effectiveness of $CuSO_4$	4	3	3	0.1	3-14,16,19,32
Praseodymium		4	4	4	4	3		3-14
Rhenium		692	4	4	4	3		3-14
Rubidium		1160	4	3	4	3		3-14
Ruthenium			4	3	4	4		3-16
Samarium		9	4	4	4	3		3-14,16
Scandium		93	4	3	4	3		3-14,16
Selenium	2.0	0.2	As and Se are antagonistic High sulfates diminish uptake of Se Toxicity decreases with increasing water hardness	1	2	1	0.05	3-14,35,38
Silver	0.003	1	Toxicity decreases with increasing water hardness	1	1	1	10 μ/m³	3-14,19,30,39
Sodium	0.3	1	Ca/Na and Ca/K act antagonistically Na is effective in reducing excessive Zn uptake	4	3	3	2	3-14,16,26,32

TABLE 3-5(b). CONCLUDED

Element or Chemical Class	Toxic Levels 2/ Aquatic 3/ (ppm)	Toxic Levels 2/ Terrestrial 4/ (mg/kg) 5/	Synergistic Potential or Other Interaction	Index of Bioaccumulation Potential	Index of Biological Impact Potential 6/ Aquatic	Index of Biological Impact Potential 6/ Terrestrial	U.S. Occupational Standards (mg/m³)	References
Strontium	1200	123	Marked antagonistic action between $NiNO_3$ and $SrNO_3$, the effect increasing with dilution	2	3	3		3-14,16,19
Tantalum		75	4	4	4	3	5	3-14
Tellurium		4	4	4	4	3	0.1	3-14
Terbium	260	4	4	4	4	3		3-14
Thallium	0.8	4	4	4	4	2	0.109	3-14
Thorium		15	4	3	4	3		3-14,16
Thulium		144	4	4	4	3		3-14
Tin	0.35	20	4	3	3	3	3.2	3-14,16
Tungsten		840	Synergistic with Co and Ti	4	4	3	5	3-14
Vanadium		1	4	4	4	4		3-14
Ytterbium		25	4	4	4	3		3-14
Yttrium		20	4	3	4	3	1	3-14
Zinc	9.2	15	Toxicity decreases with increasing water hardness	4	1	1	5	3-25,40
Zirconium		98	4	3	4	3	2.5	3-14,16

1/ Index numbers used in this table are: 1-high, 2-moderate, 3-low, and 4-investigation and evaluation of this factor is still underway at time of this report.

2/ Lethal responses to single or short-term exposure to substances are the basis for the preponderance of toxicity entries in the table. The immediate toxic effect does not necessarily characterize the cumulative effect. A value recorded as < or > indicates only the single concentration was tested and found harmful or harmless.

3/ The following aquatic organisms were used for determination of nearly all the toxic level results reported: brook trout, rainbow trout, fathead minnow, bluegill, daphnids, amphibods, and midges.

4/ The following terrestrial organisms were used for determination of nearly all the toxic level results reported: rat, mouse, guinea pig, dog, and cat.

5/ mg/kg is the amount of substance administered (ingested or injected) per kilogram of test organism weight.

6/ Relative toxicity of chemical classes disregarding emission factors.

- In most cases, the concentration for continuous exposure, estimated from the RTI formula, was far lower than concentrations that have been studied in animal or human exposures or have been measured in community or occupational epidemiologic studies. For this reason, these estimated exposure levels cannot be compared to any specific toxicologic results except for the general observation that, for most substances, estimated levels were below levels at which adverse health effects have actually been observed. For example, mechanical application of the above formulae for CO_2 produces an estimated concentration limit of 8 ppm versus a natural background level of 330 ppm.
- The estimates presented are for continuous exposure to a single pollutant. Estimates were not made for short-term exposure nor was any consideration given to pollutant synergisms or antagonisms which would influence the concentrations presented herein.

It should be stressed that these concentration limits are for screening purposes only. They are not standards but rather preliminary indications of ambient concentrations at which health effects from continuous exposure should be investigated.

In addition to the review which resulted in Tables 3-4 and 3-5, the current NO_x ambient air quality standard was reviewed in greater detail as described below.

The National Ambient Air Quality Standard for oxides of nitrogen is based on only one oxide of nitrogen — nitrogen dioxide. Nitric oxide (NO) is also a common constituent of ambient air pollution, but is nonirritant and does not appear to cause adverse health effects at typical ambient concentrations. The national primary and secondary standard for nitrogen dioxide, promulgated in April of 1971, is an annual arithmetic mean of 100 $\mu g/m^3$ (0.05 ppm).

The health criteria upon which this standard was based included few reports of human or animal response following exposure to low levels of nitrogen dioxide. Most of the available toxicologic literature pertained to nitrogen dioxide concentrations higher than those expected to occur in ambient air. The national standard for nitrogen dioxide was mostly based on a community epidemiologic study in Chattanooga, Tennessee, in which increased acute respiratory illness, increased bronchitis among elementary school children, and decreased pulmonary function of elementary school girls were associated with long-term exposure to elevated levels of nitrogen dioxide (0.062-0.109 ppm, 117-205 $\mu g/m^3$) and suspended nitrates (4-6 $\mu g/m^3$). Although the analytical method used in this study to measure nitrogen dioxide has been proven inaccurate (resulting in a reevaluation of this study), this reevaluation found insufficient cause to justify revising the national standard.*

The National Academy of Sciences' Committee on Medical and Biological Effects of Environmental Pollutants analyzed and evaluated health effects of air pollutants in 1973. They concluded that although the data base available for setting standards was inadequate, results of research since the standards were adopted have generally supported these standards.

> "None of the panels were satisfied with the data base available currently for setting the standards. Nevertheless, in general, these panels found that the evidence that has accumulated since the promulgation of the Federal ambient air quality standards by the EPA Administrator on April 30, 1971 supports those standards. In fact, the safety factors provided by the air standards are much smaller than is usual in regulating other environmental pollutants such as radioactivity. At the same time, the health risks generated when the air quality limits are exceeded are also less severe and usually more transitory than those for other pollutants. On balance, the panels found no substantial basis for changing the standards. However, the Panel on Nitrogen Dioxide suggested that consideration be given to establishing an hourly as well as an annual standard for NO_2" (Reference 3-42, p.6).

Other reviews of research on health effects of nitrogen dioxide published since adoption of the Federal standard (References 3-41 and 3-43) generally agree with this statement. In addition, the NAS report states:

> "There is sufficient information from both human and animal studies to determine the levels of NO_2 which may contribute to toxic, often fatal, reactions. There is some evidence to show that prolonged exposure to NO_2 levels of 117 $\mu g/m^3$ – 205 $\mu g/m^3$ can contribute to increased prevalence of chronic bronchitis, increased incidence of acute lower respiratory disease and diminished pulmonary function in school children. Unanswered questions still remain with respect to short-term exposure of NO_2 and the effect on acute and chronic disease, those levels of NO_2 which may contribute to systemic effects and levels of NO_2 which may be necessary to control possible adverse health effects from suspended nitrates" (Reference 3-41).

In view of these "unanswered questions" concerning short-term nitrogen dioxide exposures, the Office of Air Quality Planning and Standards has decided to defer consideration of a short-term standard to 1978 when the NO_2 air quality criteria document is revised.

Recently, the reference method for nitrogen dioxide was replaced with a new measurement principle and calibration procedure (Reference 3-44). EPA received some comments that a new reference method makes reevaluation of the present standard necessary. The EPA responded that a reevaluation was not needed, as the NAAQS incorporated an adequate margin of safety to allow for uncertainties in measurement errors.

---

*An excellent discussion of these subsequent studies is offered in EPA's Scientific and Technical Data Base for Criteria and Hazardous Pollutants (Reference 3-41).

Other speculations on the possibility of revised nitrogen oxides air quality standards have centered on the problem of nitrates and nitrosamines (Reference 3-45). In several personal communications with members of EPA's Office of Air Quality Planning and Standards, the current status of the federal standard for nitrogen dioxide was discussed specifically with reference to (1) potential changes in the annual average level due solely to the health effects of nitrogen dioxide, (2) the introduction of a short-term standard to protect health, and (3) a more stringent standard as a guide to reducing nitrates or nitrosamines.

Within EPA, a schedule has been prepared to revise all six criteria documents on which the federal air quality standards are based over the next 3 to 4 years. The criteria document for photochemical oxidants will be revised first, followed by that for hydrocarbons, nitrogen dioxide, carbon monoxide and, finally, sulfur dioxide and particulates, which will be revised together. The revised criteria document for nitrogen dioxide should be ready early in 1978. Full public hearings will be held, and within a year or so from that time, a decision is expected on whether the present federal standard for nitrogen dioxide will be revised.

No decision on a revision of the present nitrogen dioxide standard based on health effects is expected until after the criteria document has been revised. Short-term exposures to nitrogen dioxide have been a serious concern; however, as EPA assesses the present situation, insufficient data are available to support the promulgation of a short-term standard for NO_2.

Finally, it appears that a change in the present nitrogen dioxide standard as a guide to reducing nitrates or nitrosamines is unlikely within the next 5 years. EPA is aware of the evidence from recent Community Health and Environmental Surveillance System (CHESS) studies linking suspended nitrates to adverse health effects. However, this evidence by itself does not justify a new Federal standard. There is also evidence that nitrates may not exist as particulates, but as nitric acid vapor; both lines of investigation are being pursued.

Current knowledge of nitrogen oxides reactions in the ambient air does not provide convincing evidence that ambient nitrogen oxides are transformed to ambient nitrosamines. Unless there is evidence that nitrogen dioxide promotes formation of nitrosamines in the body, EPA does not foresee changes in the federal standard. It appears, then, that unless legal action specifically forces EPA to promulgate a new or revised standard for nitrogen dioxide, EPA foresees no change in the present standard until after the criteria document is revised.

3.4 SUMMARY AND CONCLUSIONS

The purpose of the impact assessment task is to provide useful limits on pollutant emissions to assist in the evaluation of NO_x control techniques. These emission limits will be used within the NO_x environmental assessment to reduce the possibility that recommended control strategies will reduce NO_x emissions only to increase other pollutants to unacceptable levels. As such, the focus of the effort reported in Section 3 has been to develop approximate limits on the ambient concentrations of a variety of pollutants. Relatively little filtering of substances (elimination of species because of low ambient concentrations) has been performed to date. Instead, data for a large number of species have been tabulated for use in screening from this stage on. Thus, the results presented in Section 3 set the stage for three levels of activity related to impact assessment:

- Initial program planning activities will identify both NO_x control processes with potential emission problems and pollutants which may be emitted in quantities that approach the threshold concentrations. This activity is initiated in Section 7 and will continue through the near future. The results will guide the selection of processes for further review, selection of pollutants requiring particular attention, and planning of tests to be conducted under the NO_x E/A.

- Additional activity under Task B.2 will reinforce the data presented in Section 3, culminating in the B.2 special report on impact assessment. Activities will include refinement of the health effects data base by additional personal contacts with researchers in the area and by including data on human health effects from ingestion as well as inhalation. The examination of pollutant effects on aquatic and terrestrial biota will be substantially augmented through an expanded literature search and through personal contacts with key researchers.

  As additional data become available in the extended B.2 study on both human health and terrestrial/aquatic effects, an attempt will be made to refine the current levels. This will reflect additional data obtained during this study and will attempt to integrate all effects data (human, aquatic, terrestrial) for a substance into one limiting concentration.

- Activities in the testing phase of this program will also address many issues currently unresolved for lack of specific data. Particular issues include the actual emissions from combustion sources employing NO_x controls (especially liquid and solid effluents), pollutant fates in the atmosphere, and the cumulative effect of actual pollutant concentrations. The data obtained in the course of testing under this and other programs, when integrated into the B.2 data base, should substantially increase confidence in the resulting concentration limits.

In addition to the data presented in Section 3.3 and the qualifications to the data presented herein, other questions have arisen which will be addressed in the program planning activities and in the continuing efforts under B.2. The topics listed below will require further attention as the NO_x E/A proceeds:

- Early in the planning process, the interaction of the impact assessment task of this program with other ongoing EPA programs will be considered. Many aspects of the present program may benefit from data being obtained from other efforts, particularly the other environmental assessments. During the near-term activities, the impact assessment task will be reexamined to minimize duplication with other programs.

- Also during the current activities, internal efforts of the EPA to set standards, particularly as these efforts are affected by recent legislative actions, will be reviewed to ensure that all future activities in this program are based on an accurate view of potential regulatory actions.

- As the research proceeds for the B.2 task on impact assessment, there are three elements which must be considered:
  - The influence of fugitive and nonstandard emissions (for example soot-blowing, boiler wash, startup, shutdown, etc.) in determining permissible concentrations,
  - The approach to be followed to consider potentially carcinogenic or mutagenic emissions,
  - The approach to define unacceptable effects on terrestrial and aquatic biota, where irreversible effects may more readily be tolerated than in human health.

- Finally the role of pollutant interaction (both synergisms and antagonisms) must be considered in designing the bioassy experiments to be conducted under the testing phase.

In general, the effort documented in Section 3 presents preliminary guidelines for permissible pollutant concentrations. These data are a conservative approach to determine whether NO_x controls are likely to cause unacceptable increases in other pollutants. Until reinforced by further activity during B.2, these data should be considered as qualitative indications of potential problems rather than precise quantitative threshold levels.

REFERENCES FOR SECTION 3

3-1. Hidy, G. M., et al., "Characterization of Aerosols in California," ACHEX, California Air Resources Board, Sacramento, California, 1974.

3-2. Hidy, G. M., in "Proceedings of the Conference on Health Effect of Atmospheric Salts and Gases of Sulfur and Nitrogen in Association with Photochemical Oxidant," (T. T. Crocker, Ed) California Air Resources Board, Sacramento, 1974, Vol. 2.

3-3. "California Air Quality Data," California Air Resources Board, 1973 to 1975.

3-4. Flocchini, R., et al., "Monitoring California's Aerosols by Size and Elemental Composition," Env. Sci. and Tech., Vol. 10:76, 1976.

3-5. Hanst, P. L., et al., "A Spectroscopic Study of California Smog," EPA 650-4-76-006, Environmental Protection Agency, Office of Research and Development, National Environmental Research Center, Research Triangle Park, North Carolina, 1975.

3-6. Handy, R. and A. Schlinder, "Estimation of Permissible Concentrations of Pollutants for Continuous Exposure," Research Triangle Institute, EPA 600-2-76-155, NTIS-PB 253 959/AS, June 1976.

3-7. Recommended NIOSH occupational standards obtained from the criteria document for that substance. For example: National Institute for Occupational Safety and Health. Criteria for a Recommended Standard . . . Occupational Exposure to Ammonia.

3-8. "Threshold Limit Values for Chemical Substances and Physical Agents in the Workroom Environment with Intended Changes for 1976," American Conference of Governmental Industrial Hygienists (ACGIH), Cincinnati, 1976.

3-9. "Registry of Toxic Effects of Chemical Substances, 1976 Edition," National Institute for Occupational Safety and Health, U.S. GPO, June 1975.

3-10. "Suspected Carcinogens; a Subfile of the NIOSH Toxic Substances List," National Institute for Occupational Safety and Health, DHEW Pub. No. (NIOSH) 75-188, U.S. GPO, June 1975.

3-11. "Revised Recommendation for an Occupational Exposure Standard for Benzene — INFORMATION," National Institute for Occupational Safety and Health, Newsletter of 25 August 1976.

3-12. "National Ambient Air Quality Standards," Code of Federal Regulations, 40 CFR 50.4 to 50.11, 1 July 1975.

3-13. "Air Quality Criteria for Hydrocarbons," U.S. Environmental Protection Agency, NAPCA Pub. No. AP-64, U.S. GPO, March 1970.

3-14. Cristensen, H. E. and T. T. Luginbyhl (Ed), "Registry of Toxic Effects of Chemical Substances," U.S. Department of Health, Education and Welfare, Rockville, MD, p. 1296, 1975.

3-15. Middleton, J. T. (Ed), "Air Quality Criteria for Photochemical Oxidants," U.S. Department of Health, Education and Welfare, Washington, D.C., 1970.

3-16. Eisler, R. and M. Wapner, "Second Annotated Bibliography on Biological Effects of Metals in Aquatic Environments," Environmental Research Laboratory, EPA 600-3-75-008, NTIS-PB 248 211/AS, 1975.

3-17. Piersol, J. R., "Effect of Ethylene on Growth of Carnations: Preliminary Report," Colorado Flower Growers Association, Inc., Bulletin 277, Denver, Colorado, 1973.

3-18. Lacasse, N. L. and W. J. Moroz, "Handbook of Effects Assessment Vegetation Damage," Center for Air Environment Studies, Pennsylvania State University, University Park, Penn., 1969.

3-19. McKee, J. E. and H. E. Wolf (Ed), "Water Quality Criteria (2nd Ed.)," The Resources Agency of California, State Water Resources Control Board Publication 3-A, 1963.

3-20. Becker, C. D. and T. O. Thatcher (Ed), "Toxicity of Power Plant Chemicals to Aquatic Life," Pacific Northwest Laboratories, Richland, Washington, 1973.

3-21. Clar, E., "Polycyclic Hydrocarbons, Vol. 2," Academic Press, New York, 1964.

3-22. Doudoroff, P. and M. Katz, "Critical Review of Literature on the Toxicity of Industrial Wastes and Their Components to Fish. I. Alkalies, Acids, and Inorganic Gases," Sewage and Industrial Wastes 22(11): 1432-1458, 1950.

3-23. Greeley, R. A., et al., "Sulfates and the Environment: A Review," MTR-6895, The Mitre Corporation, McLean, Virginia, 1975.

3-24. Copenhaver, E. D. and D. S. Harnden (Ed), "NSF-RANN Trace Contaminants Abstracts," ORNL/E15-96, Oak Ridge National Laboratory, Oak Ridge, Tenn., 1976.

3-25. Bruups, W. A., "Chronic Toxicity of Zinc to the Fathead Minnow, Pimephales Promelas Rafinesque," Trans. Am. Fish Soc. 98:212-279, 1969.

3-26. "Mercury and Air Pollution: A Bibliography with Abstracts," U.S. Environmental Protection Agency, Office of Air Programs Publication No. AP-114, 1972.

3-27. Hill, A. C. and J. H. Bennett, "Inhibition of Apparent Photosynthesis by Nitrogen Oxides," Pergammon Press, London, 1970.

3-28. Thompson, C. R., et al., "Acceptable Limits for Air Pollution Dosages and Vegetation Effects: Nitrogen Dioxide," 67th Annual Meeting of the Air Pollution Control Association, Paper 74-227, Denver, Colo., 1974.

3-29. Heggestad, H. E., et al., "Determining Acceptable Limits for Air Pollution Dosages and Vegetation Effects: Ozone," 67th Annual Meeting of the Air Pollution Control Association, Paper 74-244, Denver, Colo., 1974.

3-30. Bowen, H. J., "Trace Elements in Biochemistry," Academic Press, New York, 1966.

3-31. Hill, A. C., "Air Quality Standards for Fluoride Vegetation Effects," Journal of the Air Pollution Control Association 19:331-336, 1969.

3-32. Doudoroff, P. and M. Katz, "Critical Review of Literature on the Toxicity of Industrial Wastes and Their Components to Fish. II. The Metals, as Salts," Sewage and Industrial Wastes 25(7): 802-839, 1953.

3-33. Eaton, J. G., "Chronic Toxicity of a Copper, Cadmium and Zinc Mixture to the Fathead Minnow (Pimephales Promelas Rafinesque)," Water Research 7(11): 1723-1736, 1973.

3-34. Garton, R. R., "Biological Effects of Cooling Tower Blowdown," 71st National Meeting, American Institute of Chemical Engineers, Dallas, Texas, 1972.

3-35. Davies, P. H. and J. P. Goettle, "Aquatic Life — Western Recommendations for Heavy Metals and Other Inorganic Toxicants in Fresh Water," Submitted by Colorado Division of Wildlife for Water Quality Standards Revision Committee and Colorado Water Quality Control Commission, 1976.

3-36. Hazel, C. R. and S. J. Meith, "Bioassay of King Salmon Eggs and Sac Lay in Copper Solutions," California Fish and Game 56:121-124, 1970.

3-37. Schneider, R. F., "Impact of Various Metals on the Aquatic Environment," EPA Technical Report No. 2, 1971.

3-38. Kothny, E. L. (Ed), "Trace Elements in the Environment," American Chemical Society Advances in Chemistry Series No. 123, Washington, D.C., 1973.

3-39. Davies, P. H., et al., "Toxicity of Silver to Rainbow Trout (Salmo Gairdneri)," To be published in Water Research, 1977.

3-40. Sinley, J. R., et al., "The Effects of Zinc on Rainbow Trout (Salmo Gairdneri)," To be published in Water Research.

3-41. "Scientific and Technical Data Base for Criteria and Hazardous Pollutants — 1975 ERC/RTP Review," Health Effects Research Laboratory, EPA 600-1-76-023, 1976, NTIS-PB 253 942/AS.

3-42. "Air Quality and Automobile Emissions Control, Vol. 1, Summary Report," National Academy of Sciences — National Academy of Engineering, Coordinating Committee on Air Quality Studies, prepared for the Committee on Public Works, U.S. Senate, 93-24, 1974.

3-43. Ziskind, R. and D. Hausknecht, "Health Effects of Nitrogen Oxides," Science Applications, Inc., EPRI 571-1A (PB 251264), 1976.

3-44. "Nitrogen Dioxide Measurement Principle and Calibration Procedure," Federal Register 41 (232): 52686-52695, December 1, 1976.

3-45. Fine, D. H., et al., "A Possible Nitrogen Oxide-Nitrosamine Cancer Link," Bull. Environ. Contam. Toxicol. 11(1): 18-19, 1974.

SECTION 4

NO_x CONTROL CHARACTERIZATION

As a result of emission control regulations for new and existing stationary sources, there has been extensive development and implementation of NO_x controls in the past 10 years. Nearly all current NO_x control applications use combustion process modifications. Other approaches, e.g., modification or switching of fuel, use of alternate energy systems and post-combustion flue gas treatment are being evaluated for potential future application along with more advanced combustion process modifications. Control development experience has shown that the applicability and effectiveness of combustion process modifications are strongly dependent on the specific equipment/fuel combination to be controlled, and on whether the control is to be applied to existing field equipment or new units. Accordingly, control development efforts are directed toward specific equipment categories and fuel types. In general, the following sequence of control development is being pursued for each major equipment/fuel category:

- Minor operational adjustments
- Minor retrofit modifications
- Extensive hardware changes, either retrofit or factory-installed on new units
- Major redesign of new equipment

The progress made in this sequence varies with the importance of the source in local and national NO_x regulatory strategies. The position in the sequence will also affect how the source/control combinations will be treated in the NO_x E/A. The developmental status of control, together with results of field tests, will influence both the sequence of assessment and the level of effort in the subsequent process studies. As a first step, this section evaluates the user experience, effectiveness, developmental status and projected uses of NO_x controls in general and of specific source/control combinations. Although the emphasis is on combustion modifications, other control options are evaluated for potential far-term application.

The evaluation of NO_x control technology in this section is a link in the preliminary prioritization of source/control combinations concluded in Section 7. Section 2 gave preliminary grouping and screening of fuel combustion sources. This section notes current and impending control regulations for these sources and relates specific controls to the source to identify which source/control combinations are the most promising to achieve given levels of control. The associated evaluation of potential adverse environment impacts is given in Section 6. This effort scopes the source/controls to be evaluated in the near-term effort in the NO_x E/A. The results are further evaluated in Section 7 to scope the later effort on far-term applications of NO_x controls. Also in Section 7, the potential adverse impacts of near-term applications are screened to prioritize environmental assessment and testing requirements.

4.1 SURVEY OF NO_x CONTROL REGULATIONS

Although the emphasis in the NO_x E/A is on assessment of NO_x control techniques, some consideration must be made of the underlying regulatory strategy. This is because the relative priorities in the NO_x E/A for assessment of the various source/control combinations depend largely on the current and anticipated control implementation requirements to attain and maintain ambient air quality for NO_2. The Section 1 Introduction gave a broad overview of NO_x control implementation requirements and indicated the trend toward more widespread use of NO_x controls, particularly on new equipment. This discussion supplements that overview by citing existing and impending NO_x emission regulations for stationary fuel combustion sources. It is intended to give perspective to the subsequent review of the status and trends of control technology and to assist in setting priorities on source/control combinations.

The incentive for NO_x control development derives from two separate regulatory mechanisms, the Federal Standards of Performance for New Stationary Sources (NSPS), and the State Implementation Plans (SIPS). The NSPS are intended largely to assist in air quality maintenance by offsetting increases due to source growth. The EPA sets NSPS from time to time based on the application of the best system of emission reductions. Part of the NO_x control development effort is directed at developing and demonstrating best systems of emission reduction in support of the setting of future NSPS. The primary responsibility for air quality attainment and maintenance rests with the states. Emission standards in addition to the NSPS are set through the SIPS if required to attain and/or maintain the National Ambient Air Quality Standards in Air Quality Control Regions within the jurisdiction of the states. Part of the NO_x control development effort is directed at facilitating compliance with existing standards.

Table 4-1 summarizes the current and impending NSPS for NO_x control from stationary fuel combustion sources. All current and impending standards are based on application of combustion process modifications. To date, NO_x standards have been set only for utility and large industrial boilers. The technology to support these standards was derived in part from demonstration of retrofit controls implemented in areas with attainment problems. A more stringent standard is being considered for coal-fired units based on technology demonstrated in control development since 1971. No additional stringency is justified for new gas- or oil-fired units since no units of this type are being sold. The standard being considered for gas turbines is also based on retrofit technology demonstrated as part of SIPS. The standards under study for IC engines and industrial boilers are being based on EPA and private sector control development since there has been little retrofit control application for these sources.

As indicated in Section 1, maintenance of air quality in the 1980's and 1990's will require NO_x regulations in addition to those existing or planned. New source controls will be emphasized since experience has shown them to be more effective, less costly and less disruptive than retrofit control of existing equipment. Thus, EPA's Office of Air Quality Planning and Standards anticipates additions to the standards shown on Table 4-1. These additions may involve both inclusion of sources not presently regulated and setting more stringent standards for sources with current or impending controls. In both cases, the driving force for the standards will be the best systems of emission reductions demonstrated in the control development program.

State and local standards for new and existing stationary fuel combustion equipment are listed in Table 4-2. As is the case for NSPS, the basis for the state and local standards is application of combustion process modifications. This information was obtained through contacts with local regulatory agencies and from the Environmental Reporter (Reference 4-1). Standards for new sources which are the same as the Federal NSPS have been omitted. With the exception of the Southern California Air Pollution Control District (SCAPCD), the standards are largely directed at future air quality maintenance rather than attainment. Some areas have exercized the option to set standards more stringent than required for maintenance by the SIPS. The SCAPCD has a serious attainment problem and has accordingly instituted the most comprehensive and stringent emission regulations. In fact, the control development in the SCAPCD has been so intense that it is useful as a guide to the limits of current technology for existing gas- and oil-fired equipment. The trend in the SCAPCD and elsewhere has been toward regulating smaller equipment categories and tightening the regulations on larger equipment. The SCAPCD regulations are currently being evaluated as part of the SIP revision to determine if further emission reductions are practical.

TABLE 4-1. CURRENT OR PLANNED FEDERAL STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

T-213

Source	Status	Standard	Reference
Steam generators; heat input >73 MW (250 MBtu/hr)			
Gaseous fossil fuel-fired	Promulgated 12-23-71	86 ng/J (0.2 lb/10^6 Btu)	36 FR 24877
Liquid fossil fuel-fired	Promulgated 12-23-71	130 ng/J (0.3 lb/10^6 Btu)	36 FR 24877
Solid fossil fuel-fired (except lignite)	Promulgated 12-23-71	300 ng/J (0.7 lb/10^6 Btu)	36 FR 24877
Mixed fossil fuel-fired	Promulgated 12-23-71	$\frac{86X + 130Y + 300Z^{a}}{X + Y + Z}$ ng/J	36 FR 24877
Lignite coal-fired	Proposed 12-22-76	260 ng/J (0.6 lb/10^6 Btu)	41 FR 55792
Wood residue-fired	Amended 11-22-76	Add wood residue to permissible mixed fuel firing standard	41 FR 51397
Coal-fired (except lignite)	SSEIS[b] under review	260 ng/J (0.6 lb/10^6 Btu)	
Gas turbines; heat input >2.2 MW (7.5 MBtu/hr)	SSEIS under review	75 ppm (15 percent O_2)	
Stationary IC engines	SSEIS under review		
Intermediate size steam generators	Under study		

[a] X, Y, and Z are the percent of total heat input derived from gaseous, liquid and solid fossil fuels

[b] Standards Support and Environmental Impact Statement

TABLE 4-2. SUMMARY OF STATE AND LOCAL NO_x EMISSION STANDARDS[e]

	Equipment[d]			Standard[b]			Effective Date	Comments
	New or Existing	Type	Heat Input Capacity[a]	Gas Fired	Oil Fired	Coal Fired		
CALIFORNIA[f]								
Bay Area APCD	New	Heat transfer	>73 (250)	125 ppm	225 ppm	—		
	All	Heat transfer	≥513 (1,750)	175 ppm	300 ppm	—	4/19/75	
Monterey Bay	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
	All	Fuel burning	>440 (1,500)	125 ppm	225 ppm/hr	—		
	All	Fuel burning	>440 (1,500)	225 ppm	225 ppm	—	9/16/76	
San Diego	All	Fuel burning	≥15 (50)	125 ppm	225 ppm	225 ppm		
San Joaquin	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
	New	Fuel burning	>520 (1,775)	125 ppm	225 ppm	225 ppm	1/1/75	
Kern Co.	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
Santa Barbara APCD	New	Fuel burning		64 kg/hr[g]	64 kg/hr[g]	64 kg/hr[g]		
	Any	Fuel burning	>520 (1,775)	125 ppm	225 ppm	—	1/1/75	
Counties in SCAPCD:								
LA Co.[c]	All	Equipment	>520 (1,775)	225 ppm	325 ppm	—	12/31/71	
	All	Equipment	>520 (1,775)	125 ppm	225 ppm	—	12/31/74	
	New	Equipment	>73 (250)	125 ppm	225 ppm	—		
Orange Co.[c]	Existing	Equipment	147-630 (500-2,150)	225 ppm	325 ppm	—	12/31/72	
	Existing	Equipment	>630 (2,150)	225 ppm	325 ppm	—	12/31/72	
	Existing	Equipment		125 ppm	225 ppm	—	12/31/75	
San Bernardino Co.[c]	Existing	Equipment	>520 (1,775)	125 ppm	225 ppm	—	1/1/75	
	Existing	Steam generators	147-520 (500-1,775)	125 ppm	225 ppm	—	1/1/75	
Riverside Co.[c]	Existing	Equipment	>205 (700)	225 ppm	325 ppm		12/31/71	Applies to West Central Area Only
	Existing	Equipment	>205 (700)	125 ppm	225 ppm		12/31/74	Applies to West Central Area Only
	Existing	Equipment	>520 (1,775)	125 ppm	225 ppm		1/1/75	Applies to Balance of County

(continued on p. 4-6)

TABLE 4-2. Continued

	Equipment^d			Standard^b			Effective Date	Comments
	New or Existing	Type	Heat Input Capacity	Gas Fired	Oil Fired	Coal Fired		
SCAPCD	New	Equipment		64 kg/hr^g	64 kg/hr^g	64 kg/hr^g		
	All	Fuel burning	523-628 (1,786-2,143)	225 ppm	325 ppm	325 ppm		
Ventura Co. APCD	All	Fuel burning	>628 (2,143)	125 ppm	225 ppm	225 ppm	1/1/77	
	All	Steam generating	>163 (555)	125 ppm	225 ppm	225 ppm		
	All	Fuel burning	161-523 (550-1,786)	300 ppm	400 ppm	400 ppm		
	New	Fuel burning		64 kg/hr^g	64 kg/hr^g	64 kg/hr^g		
	New	Fuel burning	>73 (250)	125 ppm	225 ppm	—		
	All	Fuel burning	73-630 (250-2,150)	250 ppm	250 ppm	250 ppm		Except peaking units at Mandalay
CONNECTICUT	All	Fuel burning	>630 (2,150)	125 ppm	225 ppm	—		
	Existing	Fuel burning	>73 (250)	86.1 (0.2)	129 (0.3)	387.3 (0.9)		Except GT, IC
	New	Fuel burning	1.5-73 (5-250)	86.1 (0.2)	129 (0.3)	301 (0.7)		Except GT, IC
	Existing	Fuel burning	"	86.1 (0.2)	129 (0.3)	387.3 (0.9)		Except GT, IC; variances permitted
	All	GT		387.3 (0.9)	387.3 (0.9)	387.3 (0.9)		
DELAWARE								
New Castle Co.	All	Steam generators	≥147 (500)	86.1 (0.2)	129 (0.3)	129 (0.3)	7/1/76	Except for certain sources governed by operation permit
DISTRICT OF COLUMBIA	Existing	Steam generators	>29 (100)	86.1 (0.2)	129 (0.3)	301 (0.7)		Except lignite
FLORIDA Tampa	Existing	Steam boilers	>2.9 (10)	86.1 (0.2)	129 (0.3)	301 (0.7)	7/1/75	
ILLINOIS Lake, Will, Du Page, McHenry, Kara, Grundy, Kendall, Kankakee, Macon, St. Clair, Madison Cos.	Existing	Fuel combustion	≥73 (250)	129 (0.3)	129 (0.3)	387.3 (0.9)		Except cyclone & horizontally opposed fired boilers burning solid fuel
Cook Co.	New	Fuel combustion	>59 (200)	86.1 (0.2)	129 (0.3)	301 (0.7)		
	Existing	Fuel combustion	>59 (200)	129 (0.3)	129 (0.3)	387.3 (0.9)		"

TABLE 4-2. Continued

	Equipment[d]			Standard[b]			Effective Date	Comments
	New or Existing	Type	Heat Input Capacity[a]	Gas Fired	Oil Fired	Coal Fired		
INDIANA	Existing	Fuel burning	≥73 (250)	86.1 (0.2)	129 (0.3)	301 (0.7)		Applies to "Priority Basin A" only — none at present
MARYLAND	New	Fuel burning	≥73 (250)	86.1 (0.2)	129 (0.3)	215.2 (0.5)		Applies to Priority I AQCR's only
MINNESOTA	Existing	Boilers	≥73 (250)	129 (0.3)	172.1 (0.4)			
NEW MEXICO	New	Coal burning	≥73 (250)			193.6 (0.45)		
	Existing	Coal burning	≥73 (250)			301 (0.7)	12/31/74	
	New	Gas burning	≥1,055,000 GJ/yr (1,000,000 MBtu/yr)	86.1 (0.2)		301 (0.7)	12/31/74	
	Existing	Gas burning		129 (0.3)			12/31/74	
	All	Oil burning	"		129 (0.3)			
NEW YORK	All	GT, IC	≥73 (250)	86.1 (0.2)	129 (0.3)			
New York City	All	Boilers	>147 (500)	73.2 (0.17)	77.5 (0.18)	86.1 (0.2)		
NORTH CAROLINA	Existing	Boilers	≥73 (250)	258.2 (0.6)	258.2 (0.6)	559.4 (1.3)	7/1/72	
OHIO	Existing	Boilers	≥73 (250)	86.1 (0.2)	129 (0.3)	387.3 (0.9)		Applies only to Priority I regions
OKLAHOMA	New	Fuel burning	≥15 (50)	86.1 (0.2)	129 (0.3)	301 (0.7)		
SOUTH DAKOTA	All	Fuel burning		86.1 (0.2)	129 (0.3)			
TEXAS Dallas-Fort Worth & Houston-Galveston ACQR'S	All	Steam generators	>272,200 kg/hr max (>600,000 lbs/hr max) continuous capacity				8/31/72	
		Opposed fired		301 (0.7)	—	—		
		Front fired		215.2 (0.5)	—	—		
		Tangential fired		107.6 (0.25)	—	—		
VERMONT	New	Combustion	≥73 (250)	—	129 (0.3)	—	7/1/71	Except GT
	New	GT	>73 (250)	—	129 (0.3)	—	7/1/73	

(continued on p. 4-8)

TABLE 4-2. Concluded

	Equipment[d]			Standard[b]			Effective Date	Comments
	New or Existing	Type	Heat Input Capacity[a]	Gas Fired	Oil Fired	Coal Fired		
WYOMING	New	Gas burning		86.1 (0.2)	—			Except IC <59 (200)
	Existing	Gas burning		99 (0.23)				
	New	Oil burning	≥0.29 (1)	—	129 (0.3)	—		Except IC <59 (200)
	New	Oil burning	<0.29 (1)	—	258.2 (0.6)	—		Except IC <59 (200)
	Existing	Oil burning	≥73 (250)	—	197.9 (0.45)	—		Except IC <59 (200)
	Existing	Oil burning	<73 (250)	—	258.2 (0.6)	—		Except IC <59 (200)
	New	Solid fired equip		—	—	301 (0.7)		Except IC <59 (200)
	Existing	Solid fired equip		—	—	322.7 (0.75)		Except IC <59 (200) Except lignite

[a] Unless stated otherwise, units are MW (10^6 Btu/hr)

[b] Unless stated otherwise, units are ng/J (lb/10^6 Btu)

[c] Rules put into effect before SCAPCD was formed and replaced by SCAPCD rules

[d] GT refers to gas turbines; IC refers to reciprocating internal combustion engines

[e] NO_x emission standards in chronological order in so far as possible

[f] All ppm standards are at 3 percent O_2

[g] 140 lbs/hr

In summary, the sources and emission levels listed in Tables 4-1 and 4-2 establish the scope of sources and levels of controls to be evaluated in the near-term effort of the NO_x E/A to assess the incremental impacts of current NO_x control technology. The remainder of this section evaluates the available control technology to establish the source/control combinations to be emphasized in the near-term effort. It also notes the emerging technology which will be considered in the far-term as discussed in more detail in Section 7.

4.2 COMBUSTION PROCESS MODIFICATIONS

Modifying the combustion process conditions is the most effective and widely used technique for achieving moderate (40 to 60 percent) reduction in combustion-generated oxides of nitrogen. This subsection evaluates the combustion modification techniques either demonstrated or currently under development. The discussion begins by reviewing the formation mechanisms of NO_x and the general principles for suppressing NO_x emissions by process modifications.

4.2.1 General Concepts on NO_x Formation and Control

Oxides of nitrogen formed in combustion processes are due either to the thermal fixation of atmospheric nitrogen in the combustion air, which produces "thermal NO_x", or to the conversion of chemically-bound nitrogen in the fuel, which produces "fuel NO_x." For natural gas and light distillate oil firing, nearly all NO_x emissions result from thermal fixation. With residual oil, crude oil, and coal, the contribution from fuel-bound nitrogen can be significant and, in certain cases, predominant.

4.2.1.1 Thermal NO_x

During combustion, nitrogen oxides are formed by the high temperature, thermal fixation of N_2. Nitric oxide (NO) is the major product, even though NO_2 is thermodynamically favored at lower temperatures. The residence time in most stationary combustion processes is too short for NO to be oxidized to NO_2.

The detailed chemical mechanism for thermal NO formation is not fully understood. However, it is widely accepted that thermal fixation in the post-combustion zone occurs according to the extended form of the Zeldovich chain mechanism (Reference 4-2):

$$N_2 + O \rightleftarrows NO + N \qquad (4\text{-}1)$$

$$N + O_2 \rightleftarrows NO + O \qquad (4\text{-}2)$$

$$N + OH \rightleftarrows NO + H \qquad (4\text{-}3)$$

assuming that the combustion reactions have reached equilibrium. Reaction (4-1) has a large activation energy (75.8 kcal/mole) and is generally believed to be rate determining. Oxygen atom concentrations are assumed to have reached equilibrium according to:

$$O_2 + M \rightleftarrows O + O + M \qquad (4\text{-}4)$$

where M denotes any third substance (usually N_2).

In the flame zone itself, the Zeldovich mechanism with the equilibrium oxygen assumption is not adequate to account for experimentally observed NO formation rates. Several investigators have observed the production of significant amounts of "prompt" NO, which is formed very rapidly in the flame front (References 4-3 through 4-11), but there is no general agreement on how it is produced. Prompt NO is believed to stem from the existence of "superequilibrium" radical concentrations (References 4-11, 4-12, and 4-13) within the flame zone which result from hydrocarbon chemistry and/or nitrogen specie reactions, such as suggested by Fenimore (Reference 4-14). To date, prompt NO has only been explicitly measured in carefully controlled laminar flames, but the mechanism almost certainly exists in typical combustor flames as well. Of course, in an actual combustor, both the hydrocarbon and NO_x kinetics are directly coupled to turbulent mixing in the flame zone.

Recent experiments at atmospheric pressure indicate that under certain conditions the amount of NO formed in heated N_2, O_2 and Ar mixtures can be expressed as (Reference 4-15):

$$[NO] = k_1 \exp(-k_2/T)[N_2][O_2]^{1/2}t \qquad (4\text{-}5)$$

where [ ] = mole fraction

k_1, k_2 = constants

T = temperature (K)

t = time (sec)

Although this expression certainly will not adequately describe NO formation in a turbulent flame, it does summarize thermal NO_x formation. It reflects the strong dependence of NO formation on temperature. It also shows that NO formation is directly proportional to N_2 concentration and to residence time, and proportional to the square root of oxygen concentration.

Based on the above relations, thermal NO_x can theoretically be reduced using four tactics:

- Reduce local nitrogen concentrations at peak temperature
- Reduce local oxygen concentrations at peak temperature

- Reduce the residence time at peak temperature
- Reduce peak temperature

Since reducing N_2 levels is quite difficult, efforts in the field have focused on reducing oxygen levels, peak temperatures, and time of exposure in the NO_x-producing regions of a combustor. On a macroscopic scale, techniques such as lowered excess air and off-stoichiometric (or staged) combustion have been used to lower local O_2 concentrations in boilers. Since internal combustion (IC) engines and gas turbines typically operate at excess air levels far greater than stoichiometric, lowering excess air levels in these equipment classes does not control thermal NO_x. However, off-stoichiometric combustion in the form of stratified charge cylinder design has been used successfully in IC engines.

Flue gas recirculation and reduced air preheat have been used in boilers to control thermal NO_x by lowering peak flame temperatures. Analogously, exhaust gas recirculation (EGR), reduced manifold air temperature (IC engines) and reduced air preheat have been applied to IC engines and gas turbines. Other techniques designed to lower peak temperatures in prime movers include water injection and altered air/fuel ratios.

Techniques which reduce residence time at peak temperature have been more easily applied to prime mover equipment classes. Although flue gas recirculation (and EGR) reduces combustion gas residence time, it acts as a thermal NO_x control primarily through temperature reduction. Techniques which specifically reduce exposure time at high temperatures include ignition retard for IC engines and early quench with secondary air for gas turbines.

It is important to recognize that the above-mentioned techniques for thermal NO_x reduction alter combustion conditions on a macroscopic scale. Although these macroscopic techniques have all been relatively successful in reducing thermal NO_x, local microscopic combustion conditions ultimately determine the amount of thermal NO_x formed. These conditions are in turn intimately related to such variables as local combustion intensity, heat removal rates, and internal mixing effects. Modifying these secondary combustion variables at microscopic levels requires fundamental changes in combustion equipment design.

For example, recent studies on the formation of thermal NO in gaseous flames have confirmed that internal mixing can have large effects on the total amount of NO formed (References 4-16, 4-17). Burner swirl, combustion air velocity, fuel injection angle and velocity, quarl angle and confinement ratio all affect the mixing between fuel, combustion air and recirculated products. Mixing, in turn, alters the local temperatures and specie concentrations which control the rate of NO formation.

Unfortunately, generalizing these effects is difficult, because the interactions are complex. Increasing swirl, for example, may both increase entrainment of cooled combustion products (hence lowering peak temperatures) and increase fuel/air mixing (raising local combustion intensity). The net effect of increasing swirl can be to either raise or lower NO_x emissions, depending on other system parameters.

In summary, a hierarchy of effects depicted in Table 4-3 produces local combustion conditions which promote thermal NO_x formation. Although combustion modification technology seeks to affect the fundamental parameters of combustion, modifications must be made by changing the primary equipment and fuel parameters. Control of thermal NO_x, which began by altering inlet conditions and external mass addition, has moved to more fundamental changes in combustion equipment design.

4.2.1.2 Fuel NO_x

The role of fuel-bound nitrogen as a source of NO_x emissions from combustion sources has been recognized since 1968 (Reference 4-18). Although the relative contribution of fuel and thermal NO_x to total NO_x emissions from sources firing nitrogen-containing fuels has not been definitively established, recent estimates indicate that fuel NO_x is significant and may even predominate. In one recent study (Reference 4-19), residual oil and pulverized coal were burned in an argon/oxygen mixture to eliminate thermal NO_x effects. Results show that fuel NO_x can account for over 50 percent of total NO_x production from residual oil firing and approximately 80 percent of total NO_x from coal firing. Therefore, as coal is increasingly used as a national energy source, the control of fuel NO_x will become more important.

Fuel-bound nitrogen occurs in coal and petroleum fuels. However, the nitrogen containing compounds in petroleum tend to concentrate in the heavy resin and asphalt fractions upon distillation (Reference 4-20). Therefore fuel NO_x is of importance primarily in residual oil and coal firing. The nitrogen compounds found in petroleum include pyrroles, indoles, isoquinolines, acridines, and porphyrins. Although the structure of coal is not known with certainty, it is believed that coal-bound nitrogen also occurs in aromatic ring structures such as pyridine, picoline, quinoline, and nicotine (Reference 4-20).

The nitrogen content of residual oil varies from 0.1 to 0.5 percent. Nitrogen content of most U.S. coals lies in the 0.5 to 2 percent range (Reference 4-21); anthracite coals contain the least and bituminous coals the most nitrogen. Figure 4-1 illustrates the nitrogen content of various U.S. coals, expressed as lb NO_2 produced per million Btu for 100 percent conversion of the fuel

TABLE 4-3. FACTORS CONTROLLING THE FORMATION OF THERMAL NO_x

Primary Equipment and Fuel Parameters	Secondary Combustion Parameters	Fundamental Parameters	
Inlet temperature, velocity Firebox design Fuel composition Injection pattern of fuel & air Size of droplets or particles Burner swirl External mass addition	Combustion intensity Heat removal rate Mixing of combustion products into flame Local fuel-air ratio Turbulent distortion of flame zone	Oxygen level Peak temp. Exposure time at peak temp.	Thermal NO_x

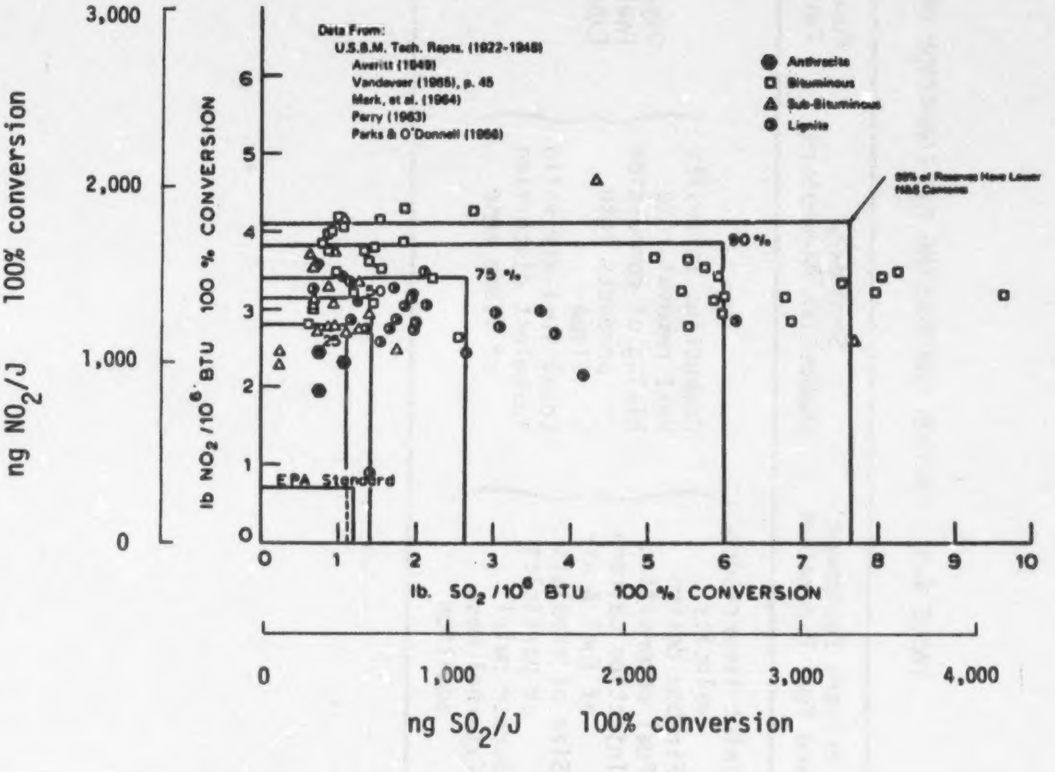


Figure 4-1. Nitrogen and sulfur content of U.S. coal reserves (Reference 4-22).

nitrogen (Reference 4-22). The figure clearly shows that if all coal-bound nitrogen were converted to NO_x, emissions for all coals would exceed New Source Performance Standards. Fortunately, only a fraction of the fuel nitrogen is converted to NO_x for both oil and coal firing, as shown in Figure 4-2 (Reference 4-23). Furthermore, the figure indicates that fuel nitrogen conversion decreases as nitrogen content increases. Thus, although fuel NO_x emissions undoubtedly increase with increasing fuel nitrogen content, the emissions increase is not proportional. In fact, recent data indicate only a small increase in NO_x emissions as fuel nitrogen increases (Reference 4-24). From observations such as these, the effectiveness of partial fuel denitrification as a NO_x control method seems doubtful.

Although the precise mechanism by which fuel nitrogen is converted to NO_x is not understood, certain aspects are clear, particularly for coal combustion. In a large pulverized coal utility boiler, the coal particles are conveyed by an air stream into the hot combustion chamber, where they are heated at a rate in excess of 10^4K/sec. Almost immediately volatile species, containing some of the coal-bound nitrogen, vaporize and burn homogeneously, rapidly (~10 msec) and probably detached from the original coal particle. Combustion of the remaining solid char is heterogeneous and much slower (~300 msec).

Figure 4-3 summarizes what may happen to fuel nitrogen during this process (Reference 4-25). In general, nitrogen evolution parallels evolution of the total volatiles, except during the initial 10 to 15 percent volatilization in which little nitrogen is released (Reference 4-26). Both total mass volatilized and total nitrogen volatilized increase with higher pyrolysis temperature; the nitrogen volatilization increases more rapidly than that of the total mass. Total mass volatilized appears to be a stronger function of coal composition than total nitrogen volatilized (Reference 4-27). This supports the relatively small dependence of fuel NO_x on coal composition observed in small scale testing (Reference 4-19).

Although there is not absolute agreement on how the volatiles separate into species, it appears that about half the total volatiles and 85 percent of the nitrogeneous species evolved react to form other reduced species before being oxidized. Prior to oxidation, the devolatilized nitrogen may be converted to a small number of common, reduced intermediates, such as HCN and NH_3, in the fuel-rich regions of the flame. The existence of a set of common reduced intermediates would explain the observations that the form of the original fuel nitrogen compound does not influence its conversion to NO (e.g., References 4-20, 4-28). More recent experiments suggest that HCN is the predominant reduced intermediate (Reference 4-29). The reduced intermediates are then either oxidized to NO, or converted to N_2 in the post-combustion zone. Although the mechanism for these conversions is not presently known, one proposed mechanism postulates a role for NCO (Reference 4-30).

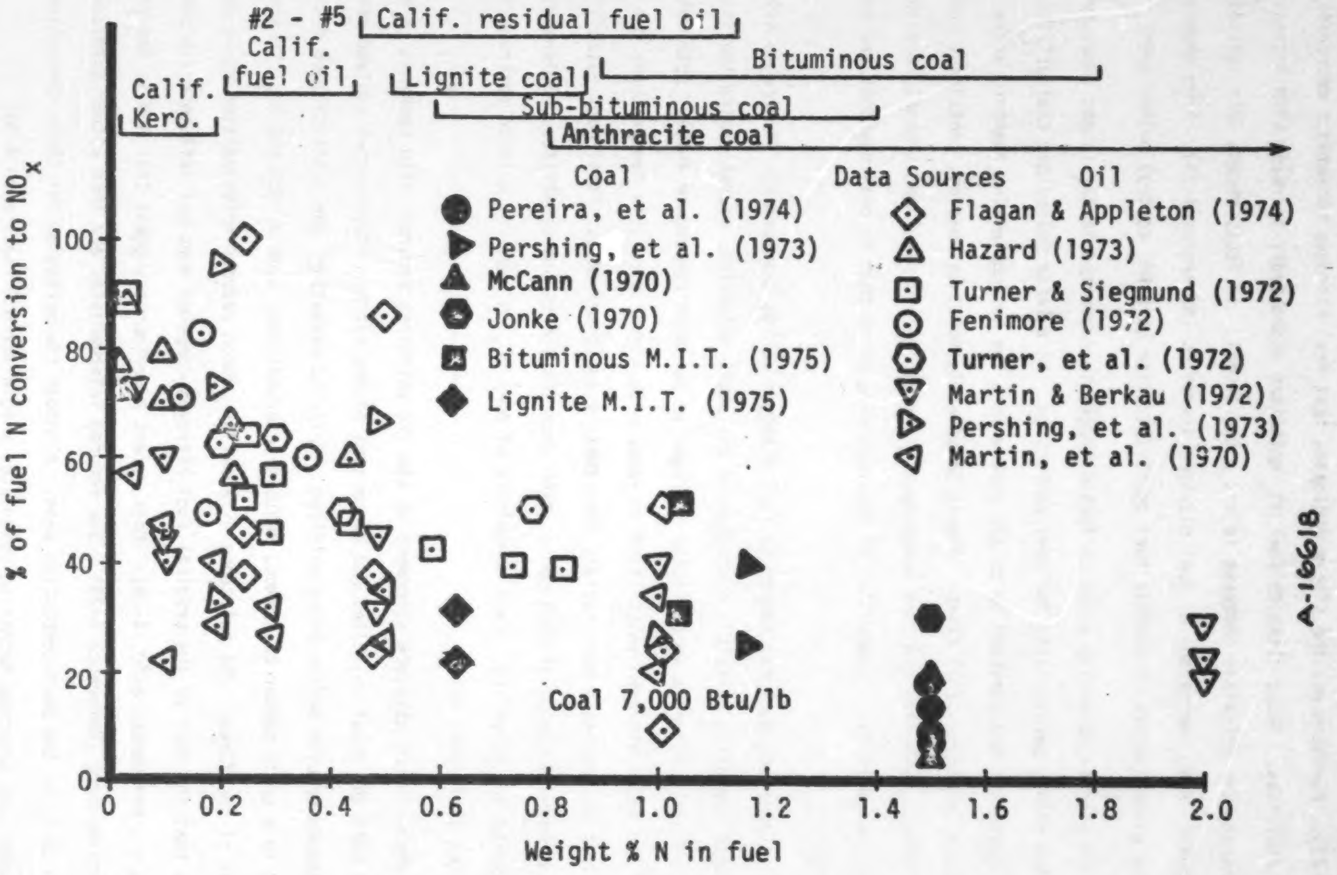


Figure 4-2. Conversion of fuel N in practical combustors (Reference 4-23).

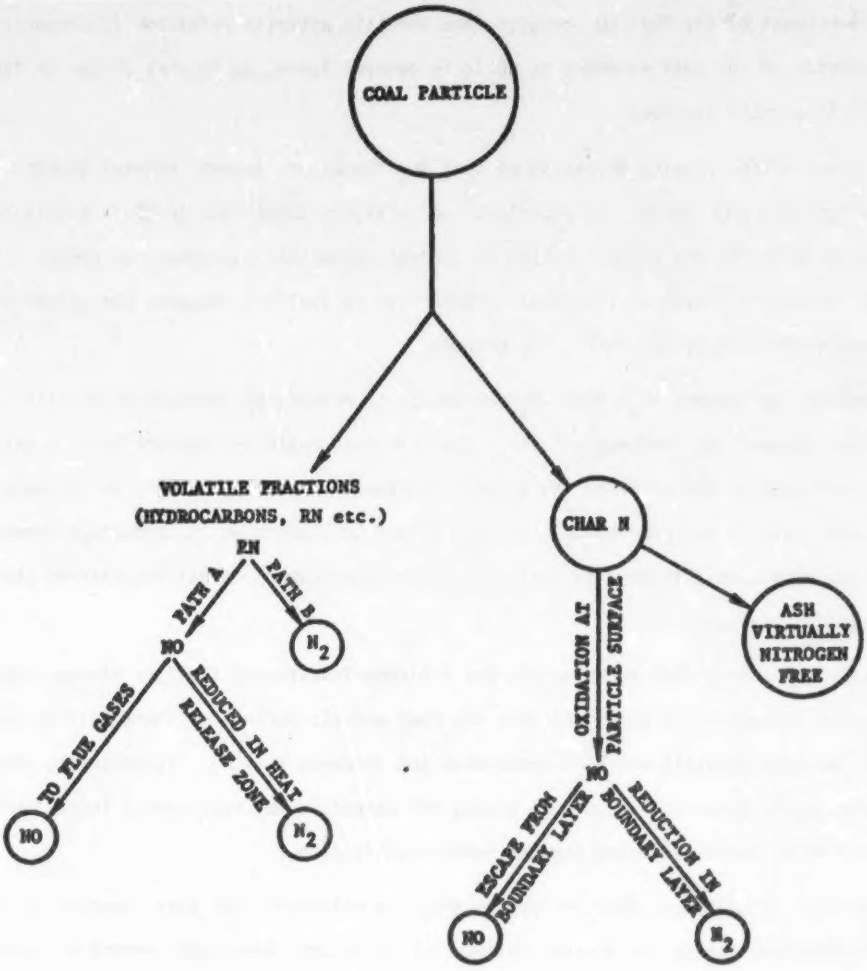

COAL PARTICLE
VOLATILE FRACTIONS
(HYDROCARBONS, RN etc.)
RN
PATH A
PATH B
NO
N_2
TO FLUE GASES
REDUCED IN HEAT RELEASE ZONE
NO
N_2
CHAR N
ASH VIRTUALLY NITROGEN FREE
OXIDATION AT PARTICLE SURFACE
NO
ESCAPE FROM BOUNDARY LAYER
REDUCTION IN BOUNDARY LAYER
NO
N_2

Figure 4-3. Possible fate of fuel nitrogen contained in coal particles during combustion (Reference 4-25).

Nitrogen retained in the char may also be oxidized to NO, or reduced to N_2 through heterogeneous reactions occurring in the post-combustion zone. However, it is clear that the conversion of char nitrogen to NO proceeds much more slowly than the conversion of devolatilized nitrogen. In fact, based on a combination of experimental and empirical modeling studies, it is now believed that 60 to 80 percent of the fuel NO_x results from volatile nitrogen oxidation (References 4-26, 4-31). Conversion of the char nitrogen to NO is in general lower, by factors of two to three, than conversion of total coal nitrogen.

Regardless of the precise mechanism of fuel NO_x formation, several general trends are evident, particularly for coal combustion. As expected, fuel nitrogen conversion to NO is highly dependent on the fuel/air ratio for the range existing in typical combustion equipment, as shown in Figure 4-4. Oxidation of the char nitrogen is relatively insensitive to fuel/air changes, but volatile NO formation is strongly affected by fuel/air ratio changes.

In contrast to thermal NO_x, fuel NO_x production is relatively insensitive to small changes in combustion zone temperature (Reference 4-28). Char nitrogen oxidation appears to be a very weak function of temperature, and although the amount of nitrogen volatiles appears to increase as temperature increases, this is believed to be partially offset by a decrease in percentage conversion. Furthermore, operating restrictions severely limit the magnitude of actual temperature changes attainable in current systems.

As described above, fuel NO emissions are a strong function of fuel/air mixing. In general, any change which increases the mixing between the fuel and air during coal devolatilization will dramatically increase volatile nitrogen conversion and increase fuel NO. In contrast, char NO formation is only weakly dependent on initial mixing and therefore may represent a lower limit on the emission level which can be achieved through burner modifications.

From the above modifications, it appears that, in principle, the best strategy for fuel NO_x abatement combines low excess air firing, optimum burner design, two-stage combustion and high air preheat. Assuming suitable stage separation, low excess air may have little effect on fuel NO, but it increases system efficiency. Before using LEA firing, the need to get good carbon burnout and low CO emissions must be considered.

Optimum burner design ensures locally fuel-rich conditions during devolatilization, which promotes reduction of devolatilized nitrogen to N_2. Two-stage combustion produces overall fuel-rich conditions during the first 1 to 2 seconds and promotes the reduction of NO to N_2 through reburning

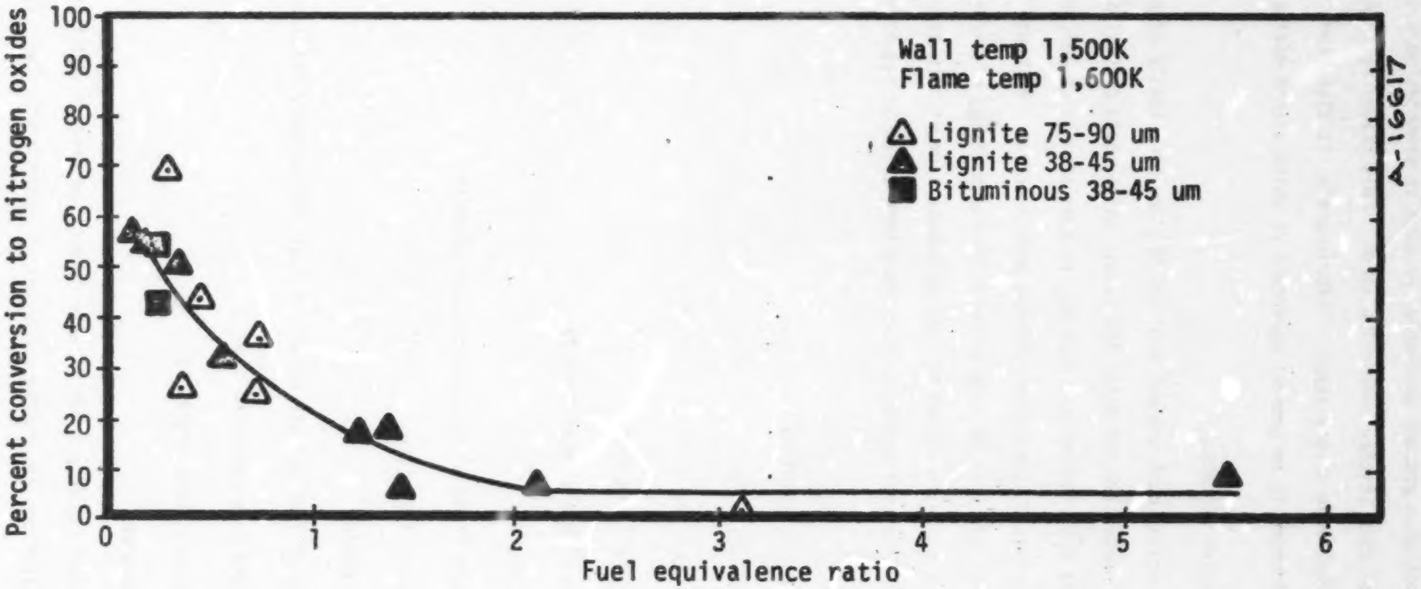


Figure 4-4. Conversion of nitrogen in coal to NO_x (Reference 4-23).

reactions. High secondary air preheat also appears desirable, because it promotes more complete nitrogen devolatilization in the fuel-rich initial combustion stage. This leaves less char nitrogen to be subsequently oxidized in the fuel-lean second stage. Unfortunately, it also tends to favor thermal NO formation, and at present there is no general agreement on which effect dominates.

4.2.1.3 Summary of Process Modification Concepts

In summary of the above discussion, both thermal and fuel NO_x are kinetically or aerodynamically limited in that their emission rates are far below the levels which would prevail at equilibrium. Thus, the rate of formation of both thermal and fuel NO_x is dominated by combustion conditions and is amenable to suppression through combustion process modifications. Although the mechanisms are different, both thermal and fuel NO_x are promoted by rapid mixing of oxygen with the fuel. Additionally, thermal NO_x is greatly increased by long residence time at high temperature. The modified combustion conditions and control concepts which have been tried or suggested to combat the formation mechanisms are as follows:

- Decrease primary flame zone O_2 level by
  - Decreased overall O_2 level
  - Controlled mixing of fuel and air
  - Use of fuel rich primary flame zone
- Decrease time of exposure at high temperature by
  - Decreased peak temperature:
    - Decreased adiabatic flame temperature through dilution
    - Decreased combustion intensity
    - Increased flame cooling
    - Controlled mixing of fuel and air or use of fuel rich primary flame zone
  - Decreased primary flame zone residence time
- Chemically reduce NO_x in post-flame region by
  - Injection of reducing agent

Table 4-4 relates these control concepts to applicable combustion process modifications and equipment types. The process modifications are further categorized according to their role in the control development sequence: operational adjustments, hardware modifications of existing equipment

TABLE 4-4. SUMMARY OF COMBUSTION PROCESS MODIFICATION CONCEPTS

T-183a

Combustion Conditions	Control Concept	Applicable Equipment	Effect on Thermal NO_x	Effect on Fuel NO_x	Primary Applicable Controls		
					Operational Adjustments	Hardware Modification	Major Redesign
Decrease primary flame zone O_2 level	Decrease overall O_2 level	Boilers, furnaces	Reduces O_2-rich, high-NO_x pockets in the flame	Reduces exposure of fuel nitrogen intermediaries to O_2	Low excess air firing	Flue gas recirculation (FGR)	
	Delayed mixing of fuel and air	Boiler, furnaces	Flame cooling and dilution during delayed mix reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burner adjustments	Low NO_x burners	Optimum burner/firebox design
	Increased fuel/air mixing	Gas turbines	Reduces local hot stoichiometric regions in overall fuel lean combustion	Increases	Improved atomization		New can design; premix, prevap.
	Primary fuel-rich flame zone	Boilers, furnaces, IC	Flame cooling in low-O_2, low-temp. primary zone reduces peak temp.	Volatile fuel N reduces to N_2 in the absence of oxygen	Burners out of service; biased burner firing	Overfire air ports, stratified charge	Burner/firebox design for two-stage combustion
Decrease peak flame temperature	Decrease adiabatic flame temperature	Boilers, furnaces, IC, gas turbines	Direct suppression of thermal NO_x mechanism	Ineffective	Reduced air preheat	Water injection, FGR	
	Decrease combustion intensity	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Minor direct effect; indirect effect on mixing	Load reduction		Enlarged firebox, increased burner spacing
	Increased flame zone cooling/reduce residence time	Boilers, furnaces	Increased flame zone cooling yields lower peak temp.	Ineffective	Burner tilt		Redesign heat transfer surfaces, firebox aerodynamics
Chemically reduce NO_x in post-flame region	Inject reducing agent	Boilers, furnaces	Decomposition	Decomposition		Ammonia injection possible on some units	Redesign convective section for NH_3 injection

or through factory-installed controls, and major redesigns of new equipment. The controls for decreased O_2 are also generally effective for peak temperature reduction but have not been repeated. The following subsections review the status of each of the applicable controls.

4.2.2 Low Excess Air Firing

Reducing the total amount of excess air supplied for combustion is an effective demonstrated method for reducing NO_x emissions from utility and industrial boilers, residential and commercial furnaces, warm air furnaces, and process furnaces. Low excess air (LEA) firing reduces the local flame zone concentration of oxygen, thus reducing both thermal and fuel NO_x formation. LEA firing is easy to implement and increases efficiency. It is, therefore, used extensively in both new and retrofit applications, either singly or in combination with other control measures. The ultimate level of excess air is limited by the onset of smoke or carbon monoxide emissions which occurs when excess air is reduced to levels far below the design conditions. Fouling and slagging may also increase in heavy oil- or coal-fired applications at very low levels of excess air.

Low excess air firing is the most widespread NO_x control technique for utility boilers. This technique was initially implemented to increase thermal efficiency and reduce stack gas opacity due to acid mist. A number of studies have shown LEA firing to be effective in reducing NO_x emissions without significantly increasing CO or smoke levels (References 4-22, 4-32 through 4-47). The major findings are summarized in Table 4-5.

Firing with excess air levels below 5 percent is now standard practice on many large oil- and gas-fired boilers (Reference 4-32). Reductions in NO_x levels average between 15 and 20 percent, although reductions up to 30 percent for gas and 35 percent for oil-fired boilers have been reported (References 4-34, 4-40). For tangentially-fired boilers, practical minimums of approximately 3 to 7 percent excess air for natural gas and oil firing are recommended. Operating at 10 percent higher excess air than the minimum established will normally increase NO_x emissions by an average of 20 percent for all fuels in these units (Reference 4-38).

With coal-fired boilers, the minimum practical levels of excess air are higher than for oil and gas. Typical values are 8 to 12 percent, but in some existing units, excess air levels below 15 to 18 percent present operating problems (Reference 4-35). For tangentially-fired units, minimum levels of 18 to 25 percent are recommended (Reference 4-38). For both wall-fired and tangentially-fired units, reductions from 12 to 20 ppm (0 percent O_2 basis) for each percentage point reduction in excess air level have been observed (References 4-35, 4-39, 4-40, and 4-44). The average reduction in NO_x levels due to LEA is approximately 20 percent from baseline conditions. For one

T-165a

TABLE 4-5. SUMMARY OF RESULTS WITH LOW EXCESS AIR FIRING

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Utility boilers						
Gas	Reduce EA to 2% to 5%	Up to 30% Avg ≈16%	Flame instability excess CO & HC emissions may occur	Up to 1% increase in efficiency	Used in all retrofit programs; no new units being built	Retrofit development to counter operating problems
Oil	Reduce EA to 3% to 7%	Up to 35% Avg ≈19%	Above plus soot, acid smut possible			
Coal (except cyclone boilers)	Reduce EA to 20% or lower	Up to 30% Avg ≈20%	Above plus slagging and corrosion possible; carbon in flyash may affect ESP	Up to 1.5% increase in efficiency	Widely used new and retrofit	Included as part of all advanced control designs
Industrial water-tube boilers						
Gas	Similar to utility boilers; same degree of EA reduction not always feasible	Wide variations reported. Approximately 5% reduction in NO_x for each one percent reduction in excess O_2. Units with preheated air exhibit greater reductions than units with no preheat.	Greater operator surveillance required to assure excessive CO & HC emissions or flame instability do not occur	Efficiency increases 0.1% per 1% decrease in excess air	Increasing use for conservation; include in new unit design	Include in R&D on external controls & low NO_x burners
Oil		7% reduction NO_x for each one percent reduction in excess O_2				
Coal		12.5% reduction in NO_x for each 1% reduction in excess O_2	In addition to the operational problem above, corrosion and slagging are possible. May reduce SO_3.			

(continued on p. 4-24)

TABLE 4-5. Concluded

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Industrial firetube boilers Gas and oil	See industrial WT and utility boilers	Approximately 5% reductions NO_x per 1% reduction in excess O_2	See industrial WT boilers	Same as for industrial WT boilers	Prototype only	Include in R&D on low NO_x burners and external controls
Residential warm air furnaces Gas and distillate oil	Ineffective in existing units; EA reduction from 80% to 15% achieved in new low NO_x units with combined NO_x controls	No consistent trend apparent. Up to 10% reductions possible.	Possible increased maintenance frequency	Efficiency increases by 0.1-0.15% per one percent decrease in excess air	Increasing use in new units	Development of burners operating at lower excess air levels (see Section 4.2.6)
Internal combustion engines Gas, dual fuel and diesel	Leaner settings of A/F ratio by either reducing fuel input (essentially derating) or by increasing the air input (through installation or replacement of turbocharger)	Reductions of up to 4.5% NO_x for 1% decrease in A/F ratio reported. Turbocharged and gas-fired units show greatest decreases.	None	Slight increase in efficiency	Not used; prototype only	Include in combustion chamber redesign

turbo-fired unit tested, reductions of approximately 24 ppm for each 1 percent decrease in excess air level were noted (Reference 4-35). Cyclone boilers are not well suited for NO_x control by LEA firing. Excess air levels in cyclone boilers are restricted to a narrow operating range to prevent corrosion and maintain furnace slagging conditions (References 4-41, 4-42).

The minimum practical level of excess air which can be achieved in existing boilers, without encountering operational problems, depends upon factors in addition to the type of fuel fired. These factors include low load operation, nonuniformity of air/fuel ratio, fuel and air control lags during load swings, use of upward burner tilt to increase steam superheat (for tangentially-fired boilers), and coal quality variation and ash slagging potential (for coal-fired boilers). They tend to increase the minimum excess air level at which the boiler can operate safely.

Other factors such as secondary air register settings and steam temperature control flexibility also affect the excess air levels. The boiler combustion control system must be modified so that the proportioning of fuel and air is adequate under all operating conditions. Uniform distribution of fuel and air to all burners is increasingly important as excess air is lowered. Excess air levels are also affected if other NO_x control techniques are employed. Off-stoichiometric combustion and operating at reduced load increases the minimum excess air levels whereas switching from eastern to western coals would decrease the levels (References 4-34, 4-44, and 4-48).

The excess air level setting of a utility boiler may be affected by considerations other than the operating limit set by excessive smoke and CO emissions. The maximum plant efficiency does not necessarily occur at the minimum excess air level (Reference 4-47). For example, problems with slagging arise in lignite-fired boilers if excess oxygen drops below about 2.5 percent in the furnace (Reference 4-49). In addition, certain high sulfur eastern coals may increase corrosion, if the excess air is dropped to levels such that local reducing atmosphere pockets occur (Reference 4-50). Medium-term tests using corrosion coupons did not show significantly accelerated rates of corrosion (Reference 4-35); long-term test results on actual furnace tubes are underway to clarify the problem. New boilers are designed to overcome some of the operational problems associated with LEA, making it possible to operate at lower levels of excess air.

LEA firing is a very effective method for controlling NO_x in industrial boilers. Although it is not in widespread use as a NO_x control technique for industrial boilers, LEA is generally considered as part of an energy conservation program. NO_x reductions of up to 44 percent of baseline levels and efficiency increases up to 2.5 percent have been reported (Reference 4-51) using LEA firing. But, it is usually not feasible to reduce the amount of excess air to the levels used in utility boilers, since industrial boilers are required to function automatically over wide variations of load with a minimum of operator supervision.

The results of several studies on industrial and packaged boilers (References 4-45, 4-52, and 4-53) are summarized in Table 4-5. Coal-fired watertube boilers showed the largest and most consistent drops in NO_x levels, averaging 72 ppm (0 percent O_2 basis) for each percent change in excess O_2. Residual oil-fired watertube boilers averaged 24 ppm reduction per 1 percent decrease in O_2, while distillate oil-fired boilers averaged about half that amount. In most cases, NO_x decreased steadily as excess O_2 was reduced. However, for equipment with premixed burners, the emissions first increase, and then decrease when the level of excess air is reduced. For gas-fired watertube boilers, no consistent reduction in NO_x with lowering of excess air is apparent, unless the combustion air is preheated. For firetube boilers, an average reduction of 7 ppm for each 1 percent reduction in excess O_2 was observed. However, for baseline levels lower than 240 ppm, firetube boilers were not very sensitive to excess O_2 levels.

LEA firing is used primarily in residential and commercial furnaces to increase the heater efficiency, not to control NO_x. As excess air is decreased in a furnace, the CO, HC, and smoke levels are minimized, whereas NO_x emissions are maximized. Normal operation of a furnace is usually bounded by excessive CO levels at high values of excess air, and excessive smoke levels at low values of excess air. However, since the furnace efficiency increases with decreasing excess air levels, furnaces are usually tuned to operate at the lowest possible excess air supply for which the flue smoke level is acceptable.

The minimum excess air levels for typical warm air furnaces vary widely, ranging from 20 to 80 percent. The change in NO_x emissions from decreasing the excess air therefore varies. Table 4-5 summarizes the results of studies on residential heaters (References 4-51, 4-54, 4-55, and 4-56). The trend for warm air furnaces is towards developing burners which will operate at lower values of excess air to reduce NO_x emissions, while increasing efficiency. An optimum geometry burner operating at about 15 percent excess air has been designed and tested (Reference 4-57). Most existing furnaces, however, must operate at excess air levels much higher than 15 percent, as the heat exchangers are not designed to withstand the flame temperatures resulting from very low excess air firing (Reference 4-58). This is discussed further in Section 4.2.6.

Changes in air-to-fuel ratio can be used to control NO_x in internal combustion (IC) engines. NO_x emissions are highest from IC engines at air/fuel ratios slightly higher than stoichiometric.

Decreasing the ratio towards fuel-rich conditions decreases NO_x but sharply increases CO and HC emissions. Therefore, the most practical use of adjusting the air-to-fuel ratio is to change the setting towards leaner operation. Injection-type engines are best suited for this technique since better control of the air-to-fuel ratio between cylinders would be necessary for carburetted engines to approach lean limit operation. Reference 4-43 surveys the use of changes in the air-fuel ratio as a NO_x control technique for IC engines; their findings are summarized in Table 4-5.

In gas turbines, the overall air-fuel ratio cannot be modified to control NO_x, since the ratio is determined by the turbine inlet temperature. However, local changes in the air-fuel ratio may be employed to control NO_x. This is discussed further in Section 4.2.6, Burner Modifications.

Limited data are available on the effect of LEA on industrial process furnaces. In some cases, the level of excess air may be dictated by process requirements (Reference 4-59). Data on some gas and oil burners used in process furnaces show NO_x emission reductions of 2 to 3 percent for each 1 percent decrease in excess air (References 4-60, 4-61). An EPA-IERL/RTP study was recently completed to collect detailed information on NO_x control methods used in industrial process furnaces (Reference 4-62).

In summary, changing the overall fuel-air ratio to control NO_x emissions is a simple, feasible, and effective technique for stationary sources of combustion, with the exception of gas turbine engines. For certain applications such as utility boilers, LEA firing is presently considered a routine operating procedure and is incorporated in all new units. Since it is efficient and easy to implement, LEA firing will see increasing use in other applications. Most sources will require additional control methods, in conjunction with LEA, to bring NO_x emissions within statutory limits. In such cases, the extent to which excess air can be lowered will depend upon the other control techniques employed. However, virtually all developmental programs for advanced NO_x controls are placing emphasis on operation at minimum levels of excess air. LEA will thus be an integral part of nearly all combustion modification NO_x controls, both current and emerging, to be assessed in the NO_x E/A.

4.2.3 Flue Gas Recirculation

Recirculation of flue gas (FGR) or exhaust gas (EGR) is a proven NO_x control technique in which a quantity of combustion products are externally recycled into the primary combustion air. The recirculated flue gas dilutes the reactants, reduces the attainable peak flame temperatures, and reduces the local oxygen concentration, thereby lowering the amount of thermal NO_x formed (Reference 4-32). Table 4-6 summarizes the status and effectiveness of FGR as applied to stationary source combustion equipment. Throughout this section, the amount of flue gas recirculation will

TABLE 4-6. SUMMARY OF RESULTS WITH FLUE GAS RECIRCULATION

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Utility boilers Gas	From 15% to 20% recirculation of flue gases to windbox; >50% used in some cases; typically used with LEA	Average about 50%	Smoking excessive vibrations, and flame instability occur at high recirculation rates	Small decrease due to fan requirement	Widely used retrofit; no new units being built	Retrofit development to combat operational problems
Oil		Up to 30%				
Coal		Up to 15%			Negligible	Inactive
Industrial water-tube boilers Gas	24% to 33% recirculation of flue gases with combustion air in windbox	Up to 73% reported	Flame instability and blowouts at high recirculation rates	None	Prototype only	Evaluation for new unit design
Oil		Up to 35% reported				
Industrial fire-tube boilers Oil	Up to 40% recirculation of flue gas in windbox	Up to 40%	Flame instability and blowouts at high recirculation rates	None	Prototype only	Evaluation for new unit design

T-164a

T-164a

TABLE 4-6. Concluded

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Comsumption		
Gas turbines						
Gas	Up to 26% recirculation of exhaust gas	30% reported	— No data available —		Only on experimental combustors	Inactive; emphasis on H_2O injection, can design
Oil		38% reported				
Internal combustion engines						
Gas	Internal recirculation by retarding valve timing, increasing back pressure, or reducing scavenging in 2-stroke engines; or external recirculation, up to 12%, of exhaust gases to the intake manifold (preferably with intercooling of exhaust gases)	Up to 37% reported	Increased fouling of valves and flow passages, increased smoke generation, and contamination of lubrication oil possible	Increase in fuel consumption from 1% up to 8% reported	Only on experimental engines	Inactive; emphasis on chamber redesign for new units
Dual fuel		Up to 25% reported				
Diesel		Up to 35% reported				

be defined as the weight fraction of recirculated flow relative to the total flow of incoming combustion air plus fuel.

FGR is widely used in utility boilers burning natural gas, since natural gas combustion produces mainly thermal NO_x. However, since natural gas is becoming less available, utility boilers have had to switch to oil. This has resulted in FGR becoming more prevalent in oil-fired units. The prospect for FGR on new utility boilers appears unlikely, since no new large oil- or gas-fired units are planned (Reference 4-63). Coal-fired units rarely use FGR for NO_x control, and the prospect of significant application of FGR to these units appears to be small. Recent tests, for example, conducted on a utility boiler burning coal show that flue gas recirculation is ineffective in controlling fuel NO_x (Reference 4-64).

With gas-fired units, NO_x reductions of 50 to 70 percent were obtained with 10 to 15 percent recirculation rates. About 45 percent NO_x reduction was attained with oil-fired units, but only 15 percent NO_x reduction was realized with one coal-fired unit, with flue gas recirculation rate of about 15 percent.

Power boilers are usually designed for recirculation of a portion of the flue gases to control steam superheat temperatures. However, when this type of control is used, the flue gases are injected into the bottom of the furnace to reduce the effectivenesss of the radiant section. This procedure, however, is relatively ineffective in suppressing NO_x (Reference 4-65).

Retrofit addition of FGR involves addition of ductwork and recirculation fans to convey the flue gas from a position upstream of the air preheater (344C, 650F) to mix with the preheated combustion air. The specific modifications required and the operational results are very much dependent on the unique characteristics of the boiler. On some units, high FGR rates have resulted in serious operational problems (References 4-66, 4-67). Boiler vibration and flame instability have resulted from the higher burner velocities and higher throughput in the furnace. On most units, these problems have been successfully combatted through control development tests, usually involving burner adjustments. The higher throughput in the furnace with FGR has also resulted in derating of some units.

The few new oil and gas boilers designed with FGR have not encountered any operational problem and have achieved excellent NO_x reductions (Reference 4-47). When combined with other control methods such as off-stoichiometric combustion, FGR has been effective with limited recirculation rates.

FGR has been tried only experimentally on industrial boilers (References 4-53, 4-68). Recent tests performed on industrial boilers show that FGR is very effective in suppressing NO_x for gas-fired units. Mixed results were obtained when FGR was used on oil-fired watertube boilers. In one case, NO_x reductions of 35 percent were obtained with 24 percent recirculation (Reference 4-53); and in another case, only a small (0 to 3 percent) amount of reduction was achieved (Reference 4-68). Both the boilers experienced flame instability at recirculation rates above 25 to 27 percent.

FGR was found to be effective in the case of an oil-fired firetube boiler; approximately 30 percent NO_x reduction was obtained with 40 percent recirculation (Reference 4-68). This result indicates that effectiveness of FGR in suppressing NO_x emissions was dependent upon boiler type.

Only a few experiments have been conducted on gas turbines with exhaust gas recirculation (EGR). Tests performed on a one-half scale combustor show that NO_x reductions of 38 percent for oil and 30 percent for gas were achieved, with an exhaust gas recirculation rate of 26 percent. No adverse effects due to EGR were detected on hydrocarbon and carbon monoxide emissions. The tests are not conclusive, however. For oil-fired units, at combustor exit temperatures below 1500F, emissions are greater with EGR than with no exhaust gas recirculation. However, for gas-fired units, EGR reduces NO_x emissions for the entire range of combustor exit temperature (Reference 4-69). EGR is not being actively pursued in the low-NO_x gas turbine combustor development programs.

On IC engines, EGR can be accomplished by either recycling exhaust gases into the intake manifold (external EGR) or by restricting the discharge of gases that would normally be exhausted from the cylinder (internal EGR). Externally recirculated gases can also be cooled before they are reintroduced into the cylinder (Reference 4-43).

The only data available on the use of cooled, external EGR in large bore engines were for a two-stroke blower scavenged test engine. The use of 20 percent cooled EGR at rated conditions resulted in a 55 percent NO_x reduction and an increase in smoke to 17 percent opacity. HC emissions were unchanged and CO emissions increased 72 percent. By comparison, 20 percent hot EGR resulted in NO_x reductions of 51 percent at rated conditions and smoke increases to 27.5 percent opacity. HC emissions were reduced 17 percent and CO emissions were increased 167 percent. Similar trends were reported on tests of cooled EGR on truck-sized engines.

Internal EGR is available for both two- and four-stroke engines, either naturally-aspirated or turbocharged. It can be used with turbocharged models, due to their leaner operation. Some of the operational problems encountered include severe fuel penalties, engine starting difficulties, and increased smoke generation. The primary maintenance problem with EGR systems is that solid exhaust products accumulate in the recirculating system. This problem is more acute for diesel engines. When EGR is applied to naturally-aspirated engines, the deposits build up in the ducts or the valves used to control the recirculation rate, and may build up on the intake valves.

EGR has only been tried experimentally for internal combustion engines; it has not been pursued further because of operational/maintenance problems and the absence of regulations to limit NO emissions from these sources.

Tests conducted on a prototype residential oil burner fired at 1 ml/s (0.951 gph) showed FGR to yield NO_x reductions comparable to burner modifications (Reference 4-56). NO_x emission rates of 0.58 g/kg fuel, compared to 2 to 3 g/kg fuel uncontrolled, resulted with 30 percent FGR. FGR has not been pursued for residential systems, however, since burner modifications have proven simple and less expensive for a comparable level of control (Reference 4-57).

In summary, the primary near-term application of FGR is in gas- and oil-fired utility boilers. Emerging applications are limited. FGR may see use in industrial boilers on a retrofit or new design basis, but alternate approaches, e.g., low-NO_x burners, off-stoichiometric combustion, are also being evaluated and may prove more attractive. Other techniques are more effective for coal-fired utility boilers, gas turbines and warm air furnaces. The effectiveness of FGR with process furnaces is under evaluation.

4.2.4 Off-Stoichiometric Combustion

Off-Stoichiometric Combustion (OSC) is a NO_x control technique in which the mixing of fuel with combustion air is controlled by the use of overfire air (OFA) ports, firing with some burners out-of-service (BOOS), or biased firing. Generally, substoichiometric conditions prevail locally in the primary combustion zone; complete combustion occurs downstream of the burners. OSC reduces both thermal and fuel NO_x. Lowering the availability of oxygen in the primary flame zone inhibits fuel nitrogen conversion, while interstage cooling by flame radiative transfer reduces peak temperatures, which, coupled with the reduced availability of oxygen, decreases the production of thermal NO_x.

OSC is a fairly common method of NO_x control for utility and large industrial boilers. It is usually implemented after simpler techniques, such as low excess air firing, fail to reduce NO_x levels below statutory requirements. Most large boilers, commissioned after 1971 are equipped with OFA ports. Older boilers with multiple burners can be adapted to OSC by biased firing, i.e., firing some burners fuel-rich and others air-rich, or by taking some burners out of service, i.e., operating them on air only. Operating on air only, however, may result in a derating of the units if the active burners or fuel delivery system do not have the capacity to carry the extra fuel required to maintain full load.

Utility boilers have been tested extensively with OSC (References 4-24, 4-32 through 4-41, 4-44, 4-47, 4-49, 4-63, 4-64, 4-70 through 4-79). Results are summarized in Table 4-7. Gas-fired boilers show the greatest reductions in NO_x, with maximum reductions of approximately 70 percent achieved with BOOS firing on one wall-fired and one tangentially-fired unit (References 4-33, 4-37). Typical reductions for gas-fired utility boilers are around 45 to 50 percent (References 4-37, 4-40, 4-73). Oil-fired boilers are less responsive to OSC, with normal decreases in NO_x levels between 25 and 35 percent, although a 55 percent reduction has been reported for one tangentially-fired unit with BOOS firing (References 4-33, 4-37, 4-40, 4-73, 4-74). For coal-fired boilers operated with BOOS firing, most NO_x reductions fall between 30 to 40 percent, with 50 percent or over achieved in a few cases (References 4-35, 4-37, 4-40, 4-41, 4-44, 4-64, 4-73, 4-75).

Recently some tests have been performed on tangential coal-fired boilers equipped with OFA ports. NO_x levels decreased by 20 to 30 percent when approximately 15 percent of the total combustion air was diverted through the OFA ports (References 4-24, 4-39). A preliminary report on western coals fired in tangential units, with 95 to 100 percent stoichiometric air at the burners, showed up to 30 percent reduction in NO_x emissions (Reference 4-76). Similarly, both wall-fired and tangential boilers firing lignite decreased NO_x emissions by about 30 percent when the air at the burners was reduced to approximately 95 percent of stoichiometric (Reference 4-49).

In other tests, a coal-fired Turbofurnace was tested with a few burners near the ends of each row operated on air only. NO_x reductions of up to 10 percent resulted when the air to active burners was reduced to 80 percent of stoichiometric (Reference 4-35). However, an attempt at firing one coal-fired cyclone boiler off-stoichiometrically by operating the upper cyclones under fuel-lean conditions did not reduce NO_x emissions (Reference 4-41). A similar attempt with an oil-fired cyclone boiler, with the upper cyclones operated on air only and with an increase in fuel supply to the lower cyclones to maintain load, actually increased NO_x emissions by 50 percent (Reference 4-40).

OSC presents a number of potential operational problems when applied to existing units. As mentioned earlier, if a unit does not have OFA ports, firing with BOOS can cause derating, especially in older coal-fired units with limited pulverizer capacities. The best BOOS firing pattern for NO_x reduction must be determined empirically for an individual boiler. In general, air-only burners in the top row give the best results; this configuration most closely simulates overfire air injection and, hence, two-stage combustion. In tests on two wall-fired oil units, with four rows of burners and OFA ports, the optimum firing pattern was to have the third row from the bottom

TABLE 4-7. SUMMARY OF RESULTS WITH OFF-STOICHIOMETRIC COMBUSTION

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Utility boilers						
Gas	Reduce oxygen level in primary flame zone by firing some or all burners fuel-rich at about 85% to 95% theoretical air. Remaining 15% to 25% of total combustion air supplied through OFA ports, BOOS, or biased burners; typically used with LEA.	Average between 45% and 50%	Load curtailment, flame instability boiler vibrations, and excessive CO and smoke emissions may occur with retrofit use	Generally little or no adverse effect	Retrofit use on over 100 boilers in the U.S.; usage increasing	Retrofit development to combat operational problems
Oil		Normally between 25% and 35%				
Coal		Normally between 30% and 40%	In addition to above, corrosion and slagging problems may arise	None in new units; possible 1% decrease with retrofit	Inclusion in most new unit designs (OFA)	Evaluate corrosion potential (near term); advanced staging concepts (long term)
Industrial boilers						
Gas	Similar to that for utility boiler	Up to 55% reported	Similar to those for utility boilers for retrofit use	Decrease in efficiency up to 3% to 4% possible	Prototype only	Evaluation for new unit design
Oil		Up to 50% possible		Maximum decrease of 1% reported		
Coal		Up to 39% reported		Decreases up to 2% reported		

firing air only. In these tests, OFA ports used alone resulted in much lower NO_x reductions. But, using the combination of BOOS and OFA firing did not result in significant reductions from using BOOS alone (Reference 4-74).

Fewer BOOS patterns are available for staging with coal-fired boilers, since it usually is not possible to close off individual coal burners from a pulverizer. Thus, all burners fed by a pulverizer are either active or on air only. In some coal-fired boiler tests where it has been possible to vary BOOS patterns systematically, burners firing air only on the top rows and on the outer edges of the burner matrix (for wall-fired units) tend to be most effective in reducing NO_x emissions at full load (References 4-36, 4-39, 4-44, 4-64). At reduced loads it is not possible to generalize which BOOS patterns result in greatest reductions. In one test, at very low load, all BOOS firing patterns tested increased NO_x emissions. This increase is attributed to the increasing levels of excess air required with decreasing load, that make it impossible to achieve substoichiometric conditions under any combination of BOOS (Reference 4-44).

In most of the tests reported, NO_x emissions decrease steadily as the stoichiometric air to active burners is reduced. Excessive smoke and CO levels generally limit the extent to which the burners are fired fuel rich. The fuel-rich conditions can lead to flame instability, and for coal-fired boilers, the reducing atmosphere in the primary combustion zone can accelerate tube corrosion and slagging (Reference 4-50).

Two utility companies have recently reported operational experience with combined OSC and FGR for gas- and oil-fired boilers (References 4-34, 4-74). Problems encountered included flame instability, boiler vibrations, load curtailment, restricted boiler load response capability, tube failures and stack smoking conditions. Another utility company reported experience with retrofit biased firing on a coal-fired boiler; problems reported included increased carbon losses, decreased boiler efficiency of about one percentage point at all load levels and possible increased tube wastage on the sidewall near the biased burners (Reference 4-44). The IERL/RTP is conducting long-term field tests to accurately determine the effect of OSC on tube wastage. Corrective measures to suppress tube wastage are also being examined. One utility boiler manufacturer uses a "curtain air" oxidizing atmosphere at the tube walls to suppress wastage and control slagging (Reference 4-75).

Few existing industrial boilers have off-stoichiometric firing capability, since most smaller units have only one or two burners and do not come equipped with OFA ports. Large industrial boilers have multiple burner assemblies which can be operated with BOOS firing, although this usually results in a derating of the unit.

In actual field tests on a number of industrial watertube boilers (References 4-53, 4-80), BOOS firing achieved maximum reductions in NO_x emissions of up to 55 percent for gas-fired boilers, 31 percent for oil-fired boilers, and 39 percent for coal-fired boilers. These tests showed that in many cases the overall excess air levels had to be increased during BOOS firing to prevent smoking. In addition, a square burner pattern proved more effective than a staggered pattern. And, removing inner burners in the top row was more effective than other burner changes in controlling NO_x emissions. Some tests with OSC were also performed on stoker-fired coal units equipped with air ports, or with auxiliary oil or gas burners which could be fired with air only located above the grate. With these units, NO_x reductions of up to 26 percent were reported. However, OSC is not effective in cases where baseline NO_x levels are already low (Reference 4-53).

Most small to medium size watertube boilers and all firetube units do not have multiple burners and therefore cannot be fired using BOOS or biased firing. These units can be fired off-stoichiometrically only by installing overfire or side fire air ports. Recent experimental results are available on single burner, oil- and gas-fired, watertube and firetube industrial boilers equipped with hardware modifications to allow for injection of air downstream of the burner (References 4-52, 4-53). These results are mixed, although NO_x reductions up to 50 percent were reported for oil- and gas-firing in one watertube unit with side fire air injection. In two cases of gas-fired units (a watertube and a firetube boiler), no significant reductions in NO_x were obtained with OSC. Moreover, in the firetube boiler, there was an obvious minimum burner stoichiometry; NO_x levels reached a minimum before rising again as the stoichiometric air to the burner was decreased. This behavior is contrary to the behavior of utility boilers and may be due to low-burner momentum under OSC inhibiting fuel-air mixing close to the burner.

Operational problems with OSC in industrial boilers are not well documented but are expected to be similar to the problems experienced in utility boilers. Some of the problems may never occur since higher levels of excess air are used in industrial boilers than in utility boilers, and the overall excess air levels increase with OSC. However, increasing the excess air level generally decreases efficiency. But, in some tests the reductions in efficiency were usually less than 1 percent (Reference 4-53). In experiments where overall excess air was carefully controlled, a slight increase in efficiency resulted (Reference 4-52).

In summary, off-stoichiometric combustion is a widely used, demonstrated technique for control of thermal and fuel NO_x from large boilers. Near-term applications to be considered in the NO_x E/A include retrofit use on gas-, oil- and coal-fired utility boilers and use of factory-installed controls on new coal-fired utility boilers. Potential emerging applications to be considered include use of factory-installed controls on new industrial boilers and use of advanced staging techniques for major redesign of utility or industrial boilers.

4.2.5 Load Reduction

Thermal NO_x formation generally increases as the volumetric heat release rate or combustion intensity increases. Reduced combustion intensity can be brought about by load reduction, or derating, in existing units and by use of an enlarged firebox in new units. The reduced heat release rate lowers the bulk gas temperature* in nonadiabatic furnaces such as boilers. Lower bulk gas temperature in turn, significantly decreases NO_x emissions (Reference 4-71).

The heat release rate per unit volume is generally independent of unit rated power output. However, the ratio of primary flame zone heat release to heat removal increases as the unit capacity is increased. This causes NO_x emissions for large units to be generally greater than for small units of similar design, firing characteristics, and fuel.

The increase in NO_x emissions with increased capacity is especially evident for gas-fired boilers, since total NO_x emissions are due to thermal NO_x. However, coal-fired and oil-fired units behave differently with regard to changes in volumetric heat release rates. Up to 80 percent of the NO_x from coal-fired boilers is attributed to fuel nitrogen conversion, so thermal effects associated with volumetric heat release rates have little overall effect. Load reduction can strongly affect firebox aerodynamics, however, and consequently affect fuel NO_x emissions. Table 4-8 summarizes field experience with load reduction for NO_x control.

During numerous field test programs, load reductions on gas- and oil-fired utility boilers reduced NO_x emissions by 10 to 55 percent for load reductions of 18 to 55 percent of maximum rated capacity. Gas-fired boilers showed the highest reduction, followed by oil- and coal-fired units (References 4-35, 4-36, 4-37, 4-40, 4-81).

A field study of industrial boilers (References 4-53, 4-80) reported that the decreased NO_x emissions resulting from load reduction were somewhat offset by the increase in excess air required for firing at the reduced load. The increased excess air was necessary to prevent CO and smoke emissions which were promoted at the reduced load condition. NO_x emissions did not change at the lower firing rates. However, watertube gas-fired boilers equipped with air preheaters showed a reduction in NO_x emissions with load reduction caused by a combination of low air preheat temperatures

---

*Bulk gas temperatures are also affected locally by circulation patterns and the proximity of cold surfaces.

T-159

TABLE 4-8. SUMMARY OF RESULTS WITH LOAD REDUCTION

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Utility boilers						
Gas	In existing units reduce load up to about 50% by decreasing fuel and air supply to all burners, or terminating fuel and air altogether to some burners. In new units, lower volumetric heat release rates achieved by up to 30% larger furnace dimensions.	About 50%	Increased soot deposits necessitate more frequent use of soot blowers. Operational problems with control of steam temperature at reduced load.	Decrease in efficiency due to associated increase in excess air levels at low load operation	Limited use for trimming to meet standards	Inactive
Oil		25% to 40%				
Coal		10% to 25%			Enlarged firebox routinely used in new units	Evaluate optimum heat release rate for advanced designs
Industrial water-tube boilers						
Gas	Reduce load by up to 60% by decreasing fuel and air supply to all burners, or terminating fuel supply to some burners	Up to 30%	Increased soot deposits necessitate more frequent use of soot blowers. Operational problems with control of steam temperature at reduced load.	Decrease in efficiency due to associated increase in excess air levels at low load operation	Not used for NO_x control	Evaluate optimum heat release rate for use with external controls or new burners
Oil		Up to 20%				
Coal		Up to 10%				
Industrial fire-tube boilers						
Gas	Reduce load up to 80% by reducing fuel and air supply to burner	Up to 20%		Decrease in efficiency at reduced loads	Not used for NO_x control	Evaluate optimum heat release rate for use with external controls or new burners
Oil		Up to 15%				

TABLE 4-8. Concluded

T-159

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Internal combustion engines						
Gas	Adjust throttle or governor setting to restrict engine power output in existing engines, or equip new engines with smaller capacity pump or carburetor	0.25% to 0.92% per 1 percent derate	Increase in HC and CO emissions	About 10% increase in bsfc	Not used for NO_x control	Inactive
Dual fuel		Up to 0.94% per 1 percent derate				
Diesel		0.17% to 0.92% per 1 percent derate				
Gas turbines						
Gas and oil	Reduce fuel flow to combustors	10% to 20%	Increase CO and smoke due to flame quench	Results in increased fuel consumption	None at present	Evaluate optimum can heat release rate for dry controls

and poor fuel-air mixing. NO_x reductions of about 20 percent were obtained as the firing rate was dropped to 50 percent of capacity.

Load reduction can lead to operational problems apart from the obvious drawback of limiting capacity. Higher levels of excess air are typically required to suppress CO or smoke emissions thus leading to an overall reduction in efficiency. The increased residence time of the combustion gases at the reduced load can cause steam temperature imbalance in the convective section. Higher excess air or flue gas recirculation may be needed to maintain superheat temperatures. Also, operation at greatly reduced load may exceed the practical turndown limit of the burners. Some burners may need to be taken out of service to maintain good firebox mixing and steam temperature control.

Most of the above problems can be avoided when the unit is designed to operate at low combustion intensity. Here, the use of enlarged fireboxes on new units produces NO_x reductions similar to load reduction on existing units. Some of the last gas- and oil-fired utility boilers sold were equipped with enlarged fireboxes. New coal-fired utility boilers use fireboxes typically 30 percent larger than was the practice in the 1960's (Reference 4-63). This practice is partly in response to the New Source Performance Standards set in 1971 and partly to facilitate combustion of lower grade western coals. As mentioned earlier, the NO_x reduction with coal-firing due to an enlarged firebox is largely indirect through the change in firebox aerodynamics.

Figure 4-5 shows a dramatic example of the effectiveness of enlarged firebox, or load reduction, in combination with other techniques (Reference 4-47). The Scattergood No. 3 unit of the Los Angeles Department of Water and Power uses a firebox rated at an electrical output of 460 MW but was converted during construction to fire at about 315 MW to meet the stringent Rule 67 emission standard in effect when the boiler went online. With natural gas firing, operation at the reduced load in combination with burners out of service and massive FGR yielded emission levels below 35 ppm.

Load reduction in internal combustion (IC) engines reduces cylinder pressure and temperatures and thus lowers NO_x formation rates. However, although NO_x exhaust concentrations (i.e., moles of NO_x per mole of exhaust) are reduced, it is possible the reductions will be no greater than the decrease in power. In such a case, brake specific emissions (i.e., grams NO_x per horsepower-hour) are not reduced, especially in four-stroke turbocharged engines.

NO_x emission reductions due to derating were reported for a variety of engine types, fuels, and percentages of derate in Reference 4-43. The reductions achieved ranged from 0.45 to 4.17 μg/J (1.2 to 11.2 g/hp-hr) for naturally-aspirated or blower scavenged engines and from 0.07 to 3.28 μg/J (0.2 to 8.8 g/hp-hr) for turbocharged units. Since these results were obtained with varying amounts

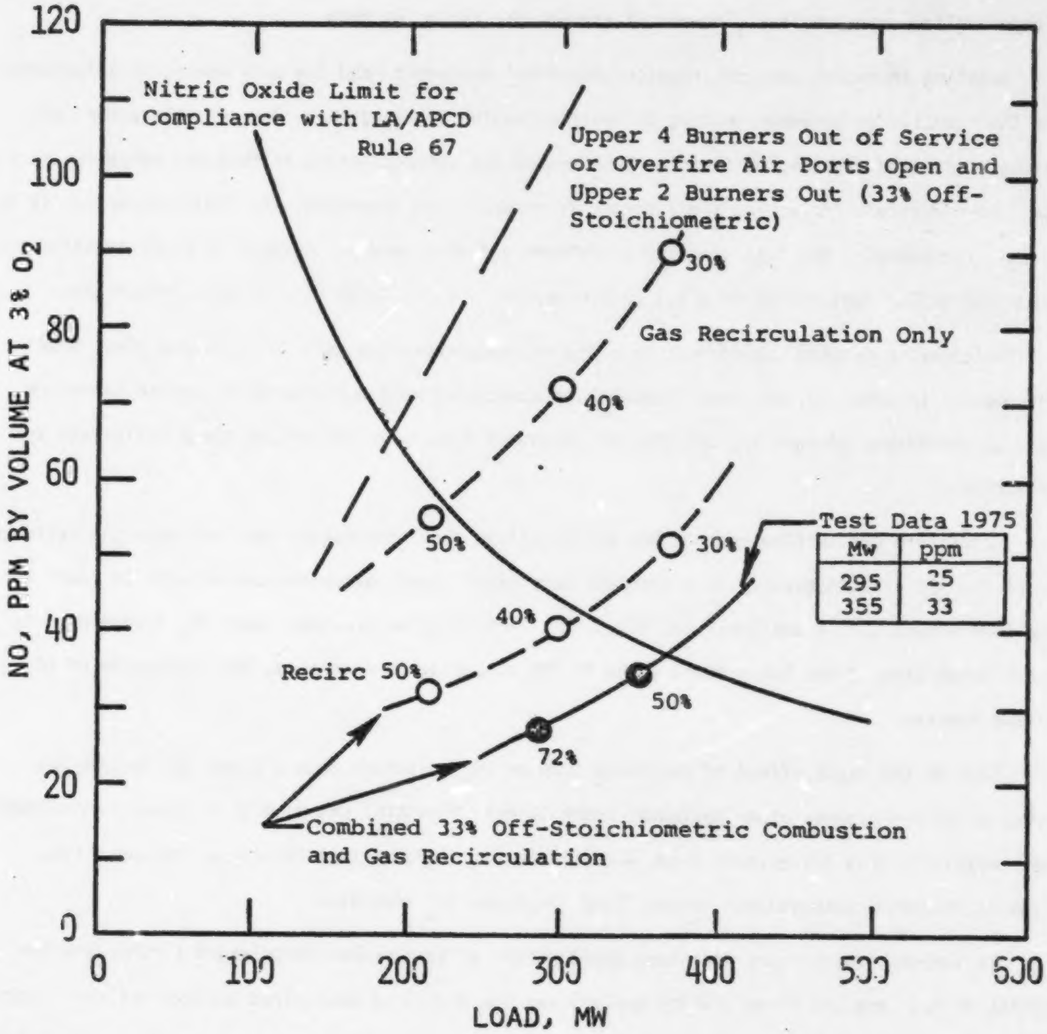


Figure 4-5. Operating results of Scattergood unit No. 3 of LADWP; nitric oxide emissions below 35 ppm (Reference 4-47).

of derating, it is more informative to compare the effectiveness of this emission control technique on a normalized basis — i.e., percent NO_x reduction per percent derate. On this basis the results for naturally-aspirated or blower scavenged engines varied from 0.25 to 6.2 whereas those for turbocharged units varied from 0.01 to 2.6. No relationship was found between normalized effectiveness and uncontrolled emission level, number of strokes per cycle, or fuel.

Derating an engine does not require additional equipment, and the only operating adjustment is to the throttle or governor setting to restrict engine power output. However, there are some problems associated with engine derating that reduce the attractiveness of this NO_x reduction technique. When derated, the engine's efficiency is reduced, and therefore, the fuel consumption is increased. For example, the data reported in Reference 4-43 showed an increase in brake specific fuel consumption (BSFC) that ranged from 1.1 to 9.6 percent for the large bore engines investigated.

Moreover, a derated engine must be a bigger, more expensive unit to satisfy a given power requirement. In addition, the lower temperature associated with derating an IC engine increases HC and CO emissions, because the temperature-dependent reactions that reduce these pollutants are less active.

Derating a gas turbine reduces the primary flame zone temperature and increases the residence time of the hot product gases. At a constant compressor speed, gases are cooled more at lower loads, since more excess air is available for diluting. This dilution produces lower NO_x formation. As the residence time of the hot product gases in the combustor is increased, the production of NO_x may increase however.

Data on the exact effect of residence time on NO_x emissions from a given gas turbine are scarce, primarily because other variables (such as mass flowrate) change with a change in residence time. Available data (References 4-69, 4-82), however, indicate that increased residence time (which is inversely proportional to air flow) increases NO_x emissions.

In summary, the primary near-term applications of load reduction/enlarged firebox are for retrofit of gas- and oil-fired utility boilers and new design of coal-fired utility boilers. Additionally, there may be application to new and existing industrial boilers as standards are set for these units. Load reduction for existing units is unattractive due to economic and operational penalties. Its use is thus avoided except as a last resort to achieve compliance with standards.

4.2.6 Burner Modifications

Burner or combustor modification for NO_x control is applicable to all stationary combustion equipment categories. With the possible exception of internal combustion engines, modified burners or combustion chambers can be retrofitted onto most existing units. Almost all burner modifications use some form of in-flame LEA, OSC, or FGR to reduce NO_x emissions.

For boilers and furnaces, a number of burner parameters affect NO_x emissions. These include the geometry of the burner and fuel injection system, the method of fuel injection, the velocity and degree of swirl of the combustion air, and the division of the total air between primary, secondary and teriary streams (References 4-16, 4-77, 4-83, 4-84, 4-85). The effect of most parameters depends upon the type of fuel used. Optimizing these parameters and developing burner design criteria have been the subjects of recent research efforts (References 4-25, 4-60, 4-86); a summary of the results is given in Table 4-9.

For boilers and furnaces fired with natural gas, burner parameters which reduce peak and average flame temperatures produce the least NO_x emissions (References 4-85, 4-86). Entrainment of cooler gases from the recirculating zones into the primary combustion zone is generally desirable. However, since secondary recirculation patterns may vary considerably (depending on the geometry of the furnace), burner parameters which reduce NO_x in one furnace may increase NO_x levels in another (Reference 4-86).

Nevertheless, several low-NO_x burners have been developed for industrial furnaces, including some unconventional Japanese designs (References 4-61, 4-86). Full scale test results show reductions in NO_x emissions from 40 to 60 percent. Subscale tests with single burners of the type normally used in utility boilers have indicated that simple changes in burner block and nozzle geometry and in swirl vane angles can decrease NO_x production by up to 55 percent (Reference 4-60).

On oil-fired boilers and furnaces, a number of modifications are possible for low-NO_x burners. The simplest modification varies the primary to secondary air ratio, swirl level, and atomization pressure on conventional burners. In tests on a simulated package boiler, decreases in NO_x emissions from about 10 to 30 percent resulted when each of the above parameters was varied individually (Reference 4-61). The reductions are caused by changes in flame shape and flow field which produce fuel-rich regions and dilution of air with combusted products.

Several low-NO_x burners with modified air and fuel injection techniques have recently been developed in Japan (References 4-61, 4-87, 4-88, 4-89). Some of the more innovative methods include: flame-splitting distributor tips which cause a flower petal flame arrangement, and atomizers with fuel injection holes of different diameters which create fuel-rich and fuel-lean combustion zones (References 4-25, 4-61, 4-88). Up to 55 percent reductions in NO_x emissions are reported with the use of these nozzle tips. However, the change in flame shape may cause problems due to impingement on walls and effectiveness may be reduced as flames interact in multiburner furnaces.

TABLE 4-9. SUMMARY OF RESULTS WITH BURNER MODIFICATIONS

T-163

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Utility boilers Gas	Control mixing of fuel and air at burner to decrease flame temp., internally recirculate combustion gases, and/or reduce availability of oxygen in primary flame zone for fuel NO_x control; burner mods allow greater flexibility with other controls	Up to 55% in single burner experimental furnace	Flame impingement on walls possible with certain burner types. Soot emissions may increase at low excess air levels.	Associated use of LEA yields higher efficiency	Limited retrofit use; burner mods routinely used to allow use of other mods (FGR, OSC)	Development, testing and commercialization of low NO_x burner
Oil		About 40% to 55% in single burner furnaces				
Coal		35% in field test on multiburner furnace			Inclusion in new unit design; limited retrofit use	Develop advanced low NO_x burner for new units
Industrial boilers Gas and oil	Same as for utility boilers	20% to 45% reported	As above	As above	Prototype unit	Approaching commercialization; advanced low NO_x burners under development
Residential and commercial furnaces Oil	Optimum burner/ firebox design using controlled fuel-air mixing, internal recirculation and controlled heat transfer for lower flame temperature	About 50% reported	None	Associated use of LEA yields higher efficiency	Field demonstrations	Approaching commercialization optimum burner/ firebox designs

TABLE 4-9. Concluded

T-163

Equipment Category/ Fuel	Combustion Method/ range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Internal combustion engines						
Gas and diesel fuel	Staged combustion by fuel rich burning in antechamber, prior to completion of combustion at lower temperatures in main chamber	Approximately 60%	None	Fuel consumption increased by 5% to 8% in one design	None at present	Evaluation for new unit design
Gas turbines, gas, kerosene and diesel oil	Dry controls through new can design; premix, prevap lean primary zone, controlled dilution	Normal range	None	Possible improved efficiency at power loads	None at present	Extensive development and testing of advanced combustor concepts

Other fuel-air modifications include a low-NO_x burner (offered by at least one company in the U.S.) for oil- and gas-fired package boilers. This burner uses shaped fuel injection ports and controlled air-fuel mixing to create a thin stubby ring-shaped flame (References 4-61, 4-87). With this modification, reductions in NO_x from 20 to 50 percent are claimed. The most extensive air-fuel modifications involve the self-recirculating and staged combustion chamber type of burners, used in industrial process furnaces. These burners are equipped with a prevaporization or a precombustion chamber in the windbox. In the chamber, the fuel is vaporized and premixed with part of the combustion air, or is allowed to undergo partial combustion under oxygen deficient conditions before being discharged into the furnace. NO_x reductions of about 55 percent are typical of these devices.

On pulverized coal burners, experiments have shown that the amount of NO_x produced in turbulent diffusion flames is strongly dependent on fuel-air mixing. High velocity axial injection of fuel delays fuel-air mixing in the central core region of the flame; this produces local off-stoichiometric conditions which inhibit NO_x production. However, the length of the flame produced by this method is generally unacceptable for use in existing boiler configurations (References 4-83, 4-84).

To reduce NO_x emissions without altering the flame form, a triple concentric burner design with tertiary air supply has been suggested. In subscale tests, NO_x reductions of about 33 to 67 percent have resulted from injecting 50 percent of the total mass of air through the tertiary ports (Reference 4-25).

One major utility boiler manufacturer has recently fabricated and tested a similar dual register pulverized coal burner, designed to produce a limited turbulence, controlled diffusion flame. The manufacturer claims NO_x reductions of 50 percent (Reference 4-90). In field tests, an existing boiler equipped with the new burners generated 35 percent less NO_x than an identical unit operating under similar conditions with old burners (Reference 4-36).

Another major manufacturer also plans to install its own version of a dual register, divided air stream burner in all its new units. The manufacturer claims that the new burners and a new furnace design (which increases burner spacing and reduces the volumetric heat release rate) will reduce NO_x emissions by 47 percent, when compared to emissions from older units (Reference 4-91).

Burner spacing and location have an important effect on NO_x production, although little quantitative data are available. Closer burner spacing increases interaction between adjacent flames and reduces the ability to radiate to cooling surfaces. In most new utility boiler designs, the spacing between burners has been extended. Future work is planned to study the influence of burner-burner and burner-furnace interactions (Reference 4-25).

Oil-fired burners used in residential heaters and furnaces have been investigated recently, and optimum burner and system design criteria have been established (References 4-55 to 4-58, 4-91, 4-92). For most burners with refractory-lined combustion chambers, local recirculation increased NO_x emissions. It was also found that for water-cooled and air-cooled combustion chambers (which characteristically have lower NO_x emissions), entrainment from the external recirculation zone, which has a chance to dissipate heat to the cold walls, is beneficial. Flame retention devices were, however, found to be detrimental for both types of combustion chambers. In addition, choke diameter dimensions as a function of fuel flowrates and optimum swirler vane angles were determined. Two burners based on these criteria were constructed, and their measured NO_x emissions were found to be approximately 50 percent lower than conventional burners operating under similar conditions.

In internal combustion engines, the combustion process can be improved by:

- Predesigning chamber geometries to increase turbulence, as in high swirl engines
- Staging, as in engines with stratified charge, precombustion chambers, or piston heat cavities
- Using a combination of both, as with "squish lip" piston heads (Reference 4-43)

In high swirl units, the improved mixing promotes rapid, early combustion which causes high temperatures for a long period of time. Delayed ignition can then be used to reduce peak temperatures below the temperatures at which NO_x forms, with less production of unburned hydrocarbons and smoke. No data are available to compare NO_x emissions from a high swirl unit with those from a conventional engine when both are retarded as far as possible.

When staged combustion is used, the fuel charge is introduced into a cavity as a rich mixture and then ignited in an oxygen-deficient environment which inhibits NO_x formation. This combusting mixture then expands into the main chamber where it mixes with additional air at reduced temperatures which are adequate for combustion, but below those required for NO_x formation. Reduced temperatures may, however, reduce the engine efficiency; the results are summarized in Table 4-9.

"Squish lip" designs appear to reduce NO_x emission both by aerodynamic effects and staged combustion. The vertical flow pattern created recirculates burned gases through the combustion zone within the piston head cavity, thus incorporating a form of internal EGR. A summary of combustion modifications for reciprocating IC engines is given in Reference 4-43.

Much research has been focused recently on the development of low-NO_x gas turbine combustors for both stationary and mobile sources (References 4-69, 4-92 through 4-100). Some of advanced combustor concepts proposed depart radically from conventional designs. In general, most combustor modifications attempt to control NO_x emissions by reduced reaction flame temperatures, decreased residence times, and controlled fuel air mixing. The techniques employed include leaning out of the primary zone, increasing of the mass flowrate, earlier quenching with secondary air, air blast and air assist atomization, fuel prevaporization, and premixing of fuel and air. Some of the more advanced designs propose heat removal from the combustion zone, precombustion, fuel staging, extended flammability limits for ultra-lean combustion, fuel-rich low-intensity combustion, and staged swirl mixing and burning. Most of these designs are still in the conceptual stage. The limited tests performed on experimental test rigs have generally produced encouraging results with NO_x reduction ranging from 35 to 60 percent of conventional combustion; the results are summarized in Table 4-9.

In summary, new optimized design burners appear to have the capability of reducing NO_x concentrations 40 to 65 percent from conventional burner designs on gas and oil fuels. Similar reductions are being demonstrated on prototype coal-fired units. The new low-NO_x burners are designed to attain controlled mixing of fuel and air in a pattern that keeps the flame temperature down and dissipates the heat quickly. Improved burner designs may well replace the external combustion modifications now in use and achieve significantly lower NO_x emissions. Thus, although low-NO_x burners have limited current application, they will receive primary emphasis in the NO_x E/A for far-term application.

4.2.7 Water Injection

Water injection has been shown to reduce flame temperature and is widely used in gas turbines. Only recently has water injection been tried on utility boilers. Table 4-10 summarizes the current state of water injection as a NO_x control method for stationary combustion sources.

The Ormand Beach, California steam-generating units were tested with water injection to reduce NO_x (Reference 4-74). The boilers, operating at 75 percent of full load (design capacity 800 MW) with 10 percent tertiary air, were emitting 400 ppm of NO. When 0.6 kg of water per kg of oil was injected, the emissions were reduced to 228 ppm, a 43 percent reduction. Higher reductions were obtained with flue gas recirculation and water injection combined. For example, with 15 percent gas recirculation and injection of 0.2 kg of water/kg of oil, NO reduction of nearly 50 percent was achieved. Compared to flue gas recirculation, water injection imposes a large energy penalty. Water injection increased the minimum O_2 requirement and significantly lowered the efficiency. For this reason, water injection seems to be an unattractive NO_x control technique for utility boilers.

T-161

TABLE 4-10. SUMMARY OF RESULTS WITH WATER INJECTION

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency Fuel Consumption		
Utility boilers						
Oil	Water sprayed into windbox 0 to 0.6 kg H_2O/kg fuel	0% to 40% (opposed wall-firing)	Increases minimum O_2 requirement-burner flame detectability problem	Lowers efficiency (by roughly 10%)	Demonstration only Southern Calif. Edison	Inactive
Coal	Water injection 0.2 kg H_2O/kg coal	15% (opposed wall firing)	Better ESP efficiency	Lowers efficiency (roughly 10%)	Demonstration only Arizona public service	Inactive
Internal combustion engines						
Gas	Water induction 0.94 kg H_2O/kg fuel	70%	Increases CO and HC emissions/ rapid buildup of scale	No data	Experimental/not used	Inactive
Diesel	0.17 to 0.21 kg H_2O/kg fuel	20% to 40%	Increases CO, HC emissions	No data	Experimental/not used	Inactive
Dual fuel	0.1 to 0.25 kg H_2O/kg fuel	50% to 70%	Increases HC emissions/engine durability decreases	No data	Experimental/not used	
Gas turbines						
Oil (distillate)	Direct injection of atomized H_2O into the primary zone 0.3 to 1.0 kg H_2O/kg fuel	30% to 80%	Small increase HC and CO emissions possible	Decreases efficiency up to 1%	Extensive retrofit use; inclusion in new unit design	Continuing development for new and retrofit use; long-term emphasis is on dry controls
Gas (natural)	0.3 to 1.0 kg H_2O/kg fuel	30% to 80%	Small increase HC and CO emissions possible	Decrease efficiency up to 1%		

Water injection has not been tried on industrial boilers and no experimental or field test data are available at this time. Based on the results obtained from utility boilers, it appears that water injection is not a viable control technique for industrial boilers.

Water can be introduced with the intake air or injected directly into the cylinder of internal combustion engines. The effectiveness of water injection/induction depends on the degree of atomization and mixing of the water within the combustion chamber; the reported effectiveness in lowering NO_x emissions depends almost linearly on the rate at which water is added. More than 30 percent NO_x reductions were obtained, for large bore engines, with 0.5 kg of water per kg of fuel. However, the effectiveness of water induction decreases at water-to-fuel ratios greater than one (Reference 4-43).

Operational/maintenance problems associated with water injection include leakage of water into the crankcase which contaminates the lubricating oil and rapid buildup of mineral scale around the valves, water injection nozzles, and other components through which the water flows. The availability of water may be a problem for those engines which are used in remote and frequently arid locations (Reference 4-43).

Over 80 percent NO_x reductions have been achieved with water injection on gas turbines. Injecting atomized water directly into the primary zone of the combustor is most effective in reducing NO_x.

The only problems involve the quality and quantity of water injected, since these determine the operational economics and life of the gas turbine. Most utilities which use water injection have some sort of purification system. According to industry sources, boiler feed water quality requirements are more stringent than those for the water injected into gas turbines (Reference 4-69).

The quantity of water used varies significantly between turbines and depends on such factors as mechanical design, plant location, heat rate, turbine inlet temperature, fuel characteristics, and operating mode. The water to fuel weight ratios vary from as low as 0.5/1 to as high as 1/1 (Reference 4-101).

The industry and manufacturing sources report that the water injection process does not appear to affect turbine life; no major problems have been encountered. However, with water injection the fuel consumption increases approximately 3 percent for water/fuel ratios of 1/1. Water injection increases the mass flow through the turbine which, in turn, increases turbine power outout. Typical increases in capacity are about 8 percent with a water/fuel ratio of 1/1 (Reference 4-69).

In summary, water injection has been found to be very effective in suppressing NO_x emissions from gas turbines. However, the use of water injection may entail some undesirable operating conditions, such as decreased thermal efficiency and increased equipment corrosion. It is, therefore, an unpopular NO_x reduction technique for all combustion equipment except for near-term use on gas turbines. In the long term, it is anticipated that water injection will be replaced by advanced combustor can design.

4.2.8 Reduced Air Preheat

NO_x emissions are strongly influenced by the effective peak temperatures in the combustion zone. Thus, any modification that lowers these temperatures, such as reducing the combustion air temperature, should lower NO_x emissions. Theory indicates that a 56K (100F) decrease in air preheat temperature will result in an approximately 28K (50F) reduction in the adiabatic combustion temperature, which in turn will decrease thermal NO_x formation by 27 percent (References 4-53, 4-72). Since reduced air preheat does not significantly suppress fuel nitrogen conversion (Reference 4-102), it is expected that this control technique would be most effective on fuels, such as natural gas and distillate oil, which have low nitrogen content.

Reduced air preheat is potentially applicable to most utility boilers, industrial boilers with preheated combustion air, regenerative gas turbine units and turbocharged internal combustion engines. This method for controlling NO_x usually greatly lowers fuel economy, however. New designs to reduce stack gas temperatures, for example, and redesigning the convective section of a boiler for more heat absorption would be necessary to maintain efficiency.

Only limited field test data are available on the effect of reduced air preheat in utility boilers due to the severe efficiency penalty incurred with this method. Some field test results and discussions on reduced air preheat for utility boilers are available in References 4-37, 4-38, 4-40, 4-47, 4-63, 4-70 through 4-73. Conclusions and results from these references are summarized in Table 4-11.

The data for coal showed varying trends, although a maximum reduction of 75 ppm (at 0 percent O_2) per 56K (100F) reduction in air temperature was reported in one case (Reference 4-102). In general, NO_x reductions of about 50 percent for gas-fired boilers and 40 percent for oil-fired boilers can be expected with reduced air preheat, however, NO_x reductions in coal-fired boilers were very small (Reference 4-63).

Industrial boilers that have combustion air preheat are usually found in sizes above 15 MW (50×10^6 Btu/hr) input capacity. Firetube boilers are generally not equipped with air preheaters. Field test results on the effects of reduced air preheat are given in References 4-45 and 4-53 and

TABLE 4-11. SUMMARY OF RESULTS WITH REDUCED AIR PREHEAT

Equipment Category/ Fuel	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Utility Boilers						
Gas	Reduce combustion air temp. from typical range of 480K to 590K to ambient temperatures, less effective for fuel NO_x	Up to 25% per 56K (100F) decrease in air preheat temperature	Induced draft fan capacity must be increased. Possible flame instability.	Significant energy penalty for existing units — about 2% drop in efficiency per 56K (100F) decrease in air preheat temperature	No use due to energy penalty	Inactive
Oil		Approx. 7% per 56K (100F) decrease in air temperature				
Coal		Generally ineffective	Preheated air is required for pulverizer operation. Coals with higher moisture contents, e.g., lignite, require higher primary air temperature.			
Internal water-tube boilers						
Gas	Reduce combustion air temp. from typical range of 395K to 620K down to ambient temperatures	Up to 25% per 56K (100F) decrease in air preheat temperature	Same as for utility boilers	Same as for utility boilers	None; trend to higher preheat for energy conservation	Some evaluation of alternate waste heat use to allow lower preheat; trend in new units generally to higher preheat
Oil		Approx. 15% per 56K (100F) decrease in air temperature				
Coal		No reliable data available				

T-160

TABLE 4-11. Concluded

Equipment Category/ Load	Control Method/ Range	NO_x Reduction	Effect On		Extent Used	R&D Status
			Operation/ Maintenance	Efficiency/ Fuel Consumption		
Internal combustion engines						
Gas	For engines with turbochargers, reduce air inlet temperatures typically from 330K down to about 310K	Up to 2.3% per 1K (1.8F) air temp decrease	Heat exchanger using air, cold water supply, or cooling tower required	Up to 1.3% increase in energy consumption	Widely used in large turbocharged engines	
Dual fuel		Up to 2.3% per 1K (1.8F) air temp decrease		Up to 0.5% increase in energy consumption		
Diesel		Up to 0.7% per 1K (1.8F) air temp decrease		Up to 1.0% increase in energy consumption		

are summarized in Table 4-11. For both industrial and utility boilers, reduced air preheat reduces efficiency, and is therefore not a practical control technique for existing units. Design changes in new units, such as installing or enlarging an economizer, are required to regain the waste heat which would otherwise be lost through the stack.

Turbocharged internal combustion engines over 373 kW (500 hp) output normally have intercoolers between the turbocharger and the intake manifold to increase the air density, permitting higher mass flow rates and consequently, higher power output. However, the intercooler which decreases the inlet temperature also causes NO_x emissions to decrease.

Results of studies cited in References 4-32 and 4-43 are summarized in Table 4-11. Reduced manifold air temperatures increase the brake specific fuel consumption, but only by a small percentage. Required hardware changes include the addition of heat exchangers or the installation of larger heat exchangers. For hot, humid climates with no access to large supplies of cold water, cooling towers must be installed.

Regenerative gas turbines use the turbine exhaust gases, which are typically at temperatures ranging from 790K to 975K (800 to 1100F), to preheat the combustor inlet air. This results in a significant improvement in overall cycle efficiency. Reference 4-73 tabulates results from tests on two similar turbines: one operating in a simple cycle, the other in a regenerative cycle. The heat rate (thermal energy consumed per unit of power output) is 18 percent lower for the regenerative unit, but the NO_x emissions are greater by more than a factor of two.

Reference 4-73 also gives NO_x emissions as a function of combustor inlet temperature as presented by Lipfert. Reducing the combustor inlet from 850K to 410K (900 to 200F) reduces NO_x by 90 percent. However, at lower temperatures, further reduction in combustor inlet temperature is not expected to lead to still lower NO_x emissions.

In summary, reduced air preheat for gas turbines and for boilers is not a practical control technique, unless the energy in the exhaust gases can be utilized effectively for other purposes. One way to use this energy is to use combined gas-steam turbine cycles; this will be discussed in Section 4.6. Reduced air preheat will be accorded low priority in the NO_x E/A.

4.2.9 Ammonia Injection

The post-flame decomposition of NO_x by reducing agents has recently shown promise as a method for augmenting combustion modifications if stringent emission limits are to be met. Exxon has patented a process for the homogeneous gas phase selective decomposition of NO_x by ammonia

(Reference 4-103). The gas phase reaction in the temperature range of 980K (1,400F) to 1370K (2,000F) converts nitric oxide, in the presence of oxygen and ammonia, into nitrogen and water vapor (Reference 4-104).

Results of lab scale tests show that the level of NO_x reduction depends on the combustion product temperature, initial NO_x concentration, and quantity of ammonia injected (Reference 4-105). Based on the available results, ammonia injection appears to be most effective between 980K (1,300F) and 1370K (2,000F), which corresponds to conditions in the convective section of large boilers. Maximum NO_x reductions, as much as 90 percent, were obtained at 1230K (1,750F) with molar ratios of ammonia to initial nitric oxide ranging from 1.0 to 1.5.

Field tests were conducted on a gas-fired furnace rated at 147 kW (500 MBtu/hr), and on an oil-fired boiler rated at 41 kW (140 Btu/hr) with both the units retrofitted for NH_3 injection (Reference 4-104). A reduction in NO_x of nearly 70 percent was obtained with a NH_3/initial NO_x ratio of 4.5. Table 4-12 summarizes the available test results to date.

Although ammonia injection is a promising technique, there are a number of developmental questions which must be answered before its full potential can be assessed. The first is the applicability of ammonia injection to existing utility boilers and to systems other than steam generators. Ammonia injection appears to have potential for new utility boilers and large industrial boilers since the required temperature range is compatible with current convective section design. New units could conceivably be designed to include ammonia injection cavities in the convective sections. Applications to existing units may be limited by the absence of the precise residence time-temperature conditions required for the process. Additionally, ammonia injection seems to be limited for other equipment types such as gas turbines and IC engines because the required time-temperature constraint cannot practically be met.

The second question concerns the ability to maintain adequate convective section temperatures required for selective reduction during boiler load changes. Normally, during load reduction, the convective section temperature will reduce substantially below the base load level. The temperature excursions during load reduction could easily move out of the range where ammonia injection is effective. Load following capability may thus be a limitation on ammonia injection for nonbase-loaded units.

The third question concerns the effectiveness and environmental impact of the process, particularly with coal firing. The process has been demonstrated on oil- and gas-fired units but is just starting to be studied in coal-fired pilot scale units. Environmental concerns with ammonia

TABLE 4-12. SUMMARY OF RESULTS WITH AMMONIA INJECTION

T-167

Equipment/ Description	Temperature Range Tested (K)	Range of NH_3 concentration (ppm)	Range of Initial NO_x Concentration (ppm)	Range of Final NO_x (ppm)	Comments/ Remarks
Experimental combustor, 59 kW (200,000 Btu/hr) firing either gas or oil	920-1,480	0-5,250	100-1,000	10-100	Maximum NO_x reduction occurs at 1,230K, most effective with high initial NO_x concentrations
Experimental tubular reactor	870-1,300	400	250	10-100	Maximum NO_x reduction occurs at 1,230K (without H_2 injection)
	870-1,300	400	250	10-250	Maximum reduction occurs at 980K with H_2 addition
Oil fired 41 MW (140 MBtu/hr)	—	$\frac{NH_3}{NO_{initial}} = 1$ to 4.5	—	30-65% reduction	—
Gas-fired furnace 147 MW (500 MBtu/hr)	—	$\frac{NH_3}{NO_{initial}} = 1$ to 4.5	—	30-80% reduction	

injection include the presence of ammonia as a primary pollutant in the stack gas and potential reactions of ammonia with the flyash and sulfur compounds in coal firing. Since low temperature stack gas reactions are important here, pilot scale tests will be of limited use. Full quantification of potential adverse impacts of ammonia injection will await full scale demonstrations with coal firing.

In addition to the above operational concern, there is also the strategic question of whether sufficient ammonia would be available in the 1980's and 1990's for widespread application in utility boilers (Reference 4-106).

In summary, ammonia injection does not appear to have near-term application for NO_x control in the U.S. It shows promise for far-term applications, however, and will be given primary emphasis in the NO_x E/A for assessment of advanced concepts for the 1980's and 1990's.

4.2.10 Costs of Combustion Process Modifications

This section presents the most recent data on capital and operating costs of combustion modification NO_x controls for each equipment category. Except where otherwise noted, the costs presented here are in 1974 dollars. In some cases, earlier cost figures have been converted to 1974 dollars by applying appropriate inflation factors.

In several cases the costs presented are for combined NO_x controls. Generally, the effecttiveness of combined NO_x controls is not equal to the sum of the individual effects of each control. Likewise, the costs of combined controls are not the sum of the costs of single controls.

4.2.10.1 Utility Boilers

The cost-effectiveness and related costs of combustion modifications in full-scale combustion equipment for utility boilers have been fairly well documented. One of the earliest efforts was attempted by Esso Research Labs in 1969 (Reference 4-107). Since 1969, however, it has been shown that the effectiveness of control techniques among boilers varies widely and requires continuing cost-effectiveness evaluations on an individual boiler basis. The most recent cost data for both new and existing tangential, coal-fired utility boilers (Reference 4-108) are summarized in Figures 4-6 and 4-7. The costs are for the combined use of overfire air ports and low excess air firing, as this is the preferred control system for tangential coal-fired boilers. Capital costs were projected over a unit size range of 25 to 1000 MW. The corresponding annual operating costs for 500 MW units was 0.006 mils/kWhr for a new unit and 0.021 mils/kWhr for existing units. Figure 4-6 applies to new unit designs with heating surfaces adjusted to compensate for the resultant

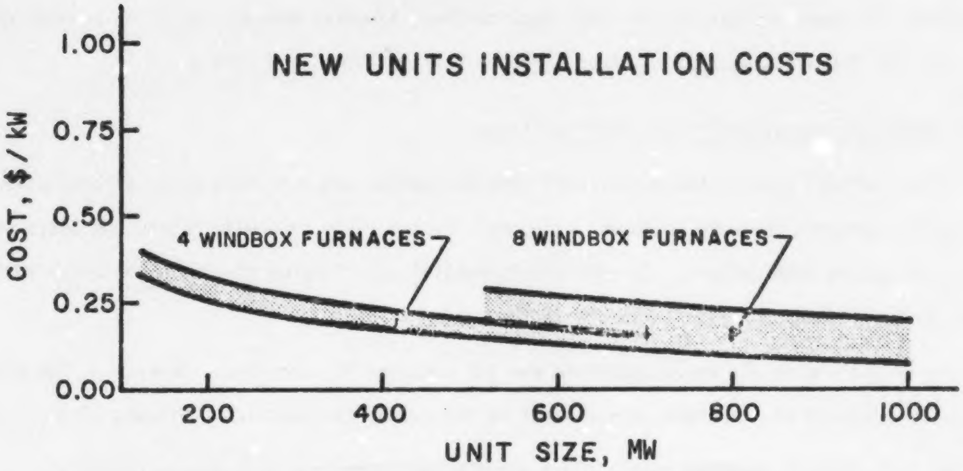


Figure 4-6. 1975 capital cost of OFA on new tangential coal-fired boilers (Reference 4-39).

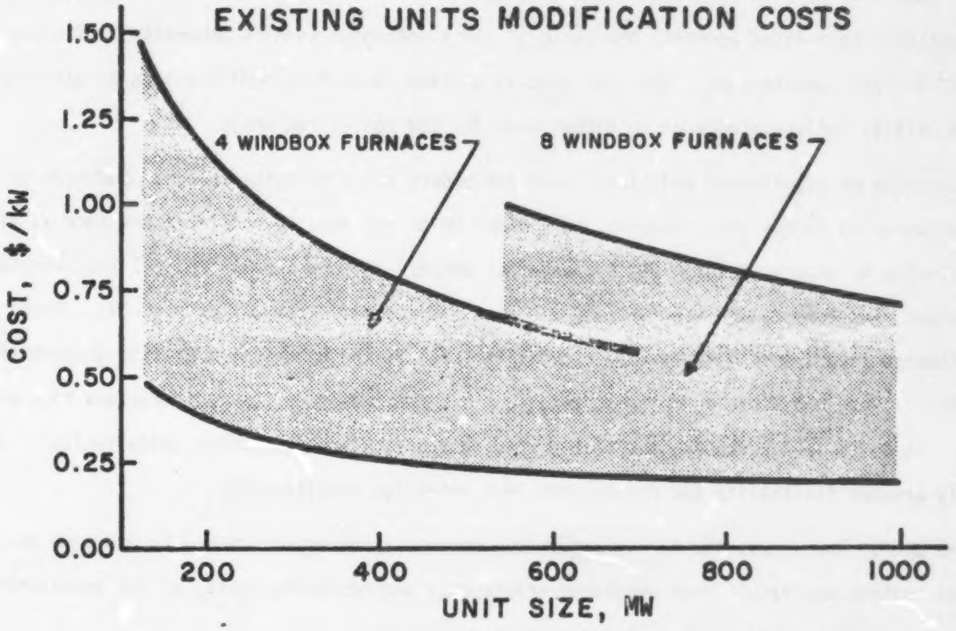


Figure 4-7. 1975 capital cost of OFA on existing coal-fired boilers (Reference 4-39).

changes in heat transfer distribution and rates. Figure 4-7 applies to existing units with no change in heating surface, as these changes must be calculated on an individual unit basis.

Cost ranges for existing units vary more widely than for new units, since variations in unit design and construction can either hinder or aid the installation of a given NO_x control system. Also, above approximately 600 MW, single cell-fired boilers exceed a practical size limit and divided furnace designs are utilized. Since a divided tangentially-fired furnace has double the firing corners of a single cell furnace, the costs increase significantly.

It should be kept in mind that although these cost data for utility boilers were developed for tangentially coal-fired boilers, the range of costs presented is also generally applicable to wall-fired boilers burning coal. And, the cost of similar combustion modifications on gas- and oil-fired utility boilers should be no higher than for the coal-fired units.

Generally no significant additional cost for modern units or units in good condition is required for reducing excess air. However, some older units may require modifications such as altering the windbox by adding division plates, separate dampers and operators, fuel valving, air register operators, instrumentation for fuel and air flow and automatic combustion controls. Table 4-13 shows estimated investment costs for low excess air (LEA) firing on existing utility boilers (Reference 4-109). These costs are guidelines, which can vary depending on the modifications that are required. As unit size increases, the cost per kW decreases since the larger units typically have inherently greater flexibility and may require less extensive modification.

The use of low excess air firing reportedly increases boiler efficiency by 0.5 to 5 percent. Additional savings may result from decreased maintenance and operating costs, so any investment costs can be offset by savings in fuel and operating expenses.

As an example of cost variations for combustion modifications among individual existing units, several case studies from Pacific Gas and Electric are presented in Table 4-14. The numbers shown are the costs incurred by PG&E during a recent program to bring eight units into compliance with local NO_x emission regulations. For the most part, the conversions involved the combination of windbox flue gas recirculation and overfire air ports. The average cost of the modifications is about, in 1975 dollars, $10/kW (Reference 4-110).

Another West Coast electric utility company, the Los Angeles Department of Water and Power (LADWP), has had extensive experience in implementing NO_x control techniques on its gas- and oil-fired boilers. The techniques currently utilized by the Department include burners out-of-service (BOOS), overfire air/NO_x ports, and low excess air. Although the units are operated with the lowest

TABLE 4-13. 1974 ESTIMATED INVESTMENT COSTS FOR LOW EXCESS AIR FIRING ON EXISTING BOILERS NEEDING MODIFICATIONS (Reference 4-109)

Unit Size (Electrical Output) (MW)	Investment Cost ($/kW)	
	Gas and Oil	Coal
1000	0.12	0.48
750	0.16	0.51
500	0.21	0.55
250	0.33	0.64
120	0.53	0.73

TABLE 4-14. 1975 INSTALLED EQUIPMENT COSTS FOR EXISTING PG&E RESIDUAL OIL-FIRED UTILITY BOILERS (Reference 4-110)

T-134A

Unit Name	Design Type	Year Online	Capacity (MW)	Modification Cost ($$10^6$)	$/kW	Year Modified	Type of Modification
Pittsburg #7	CE tangentially-fired, divided	1972	730	6.2	8.5	1975	Windbox FGR, Overfire Air ● Two new 5000 hp FGR fans ● FGR ducting (17% FGR) ● NO_x port installation ● No new burner safeguard system
Pittsburg #5 and #6	B&W opposed-fired	1964	330 (each)	7.8 (both)	11.8	1975	Windbox FGR, Overfire Air ● Transferred two FGR fans from other units ● FGR ducting (17% FGR) ● New hopper ● NO_x port installation; one for each burner column ● New burner safeguard system; computer, NO_x control board, O_2 controls on dampers, flame scanners
Contra Costa #9 and #10	B&W opposed-fired	1965	345 (each)	6 (both)	8.7	1975	Windbox FGR, Overfire Air ● New FGR fans (1 ea.) (17% FGR) ● Nominal amount of new ducting to windbox ● NO_2 port installation
Portrero #3	Riley turbo-fired	1972	206	3.5	17	1975	Windbox FGR, Overfire Air ● New FGR fan (17% FGR) ● NO_x port installation, nominal amount of ducting ● New burner safeguard system, NO_x control board, computer
Moss Landing #6-1 and #7-1	B&W opposed-fired	(?)	750 (each)	2.8	1.8	1971	Windbox FGR, Overfire Air ● Existing temperature control FGR fans replaced with larger fans ● New flame scanners

excess air possible, it has been found that when LEA is combined with other reduction methods, excess air levels must be increased beyond those normally required.

The Department's data indicate a unit efficiency decrease of approximately 1 percent attributable to BOOS operation. As found by other operators, LEA tended to increase efficiency slightly; a 1 percent decrease in excess oxygen increased efficiency by about 0.25 percent. Properly retrofitted, overfire air had no effect on efficiency.

The NO_x control costs incurred by LADWP are shown in Table 4-15 for four different units. The figures for the BOOS techniques reflect the R&D costs that precede the retrofit. All costs are installed equipment costs which include the labor required to implement the control methods. The very low expense associated with overfire air on the B&W 235 MW unit is due to the base year of the estimate (1964 to 1965), and to the fact that this modification was included in the original boiler design.

The overfire air costs for the B&W 235 MW unit are somewhat low in Table 4-15. The LADWP boilers were, for the most part, modified without much difficulty, and the associated costs probably represent the lower limits of the costs for the three NO_x reduction tecniques implemented (Reference 4-111).

In addition to the increased capital costs from including a NO_x reduction system in new or existing units, the increased unit operating costs must be considered. These differential operating costs were defined for 500 MW new and existing utility boilers and are shown in Table 4-16 (Reference 4-108). The costs are given in 1975 dollars, and the equipment costs shown are determined from Figures 4-6 and 4-7. To put these operating costs in perspective, they can be compared to the percent increase in generating costs shown at the bottom of Table 4-16. Except for the case of older units, the difference in operating cost is below 0.1 percent of annual cost.

In summary, the following are the major economic considerations that the boiler operator or designer may be faced with:

- The lowest cost method for reducing NO_x emission levels on new and existing units is the incorporation of low excess air firing. Minimal additional costs are involved.
- For most utility boilers, the second lowest cost NO_x control method appears to be off-stoichiometric combustion by biased firing, "burners out-of-service" (BOOS) or the addition of an overfire air system. Although lowering excess air (LEA) is implemented concurrently with other control techniques, the excess air levels may have to be increased beyond those normally required.

TABLE 4-15. LADWP ESTIMATED INSTALLED 1974 CAPITAL COSTS FOR NO_x REDUCTION TECHNIQUES ON GAS- AND OIL-FIRED UTILITY BOILERS (Reference 4-111)

Unit Capacity (MW)	Unit Type	NO_x Reduction Technique	Implementation Method	Estimated Cost ($)	$/kW
180	C.E. tangentially-fired	BOOS	Retrofit	69,400	0.38
		LEA	Retrofit	28,900	0.16
235	C.E. tangentially-fired	BOOS	Retrofit	75,200	0.32
		LEA	Retrofit	28,900	0.12
235	B&W Opposed-fired	BOOS	Retrofit	75,200	0.32
		Overfire air	Original Design	14,000[a]	0.06
		LEA	Retrofit	28,900	0.12
350	B&W Opposed-fired	BOOS	Retrofit	266,000	0.76
		Overfire Air	Retrofit	100,600	0.29
		LEA	Retrofit	28,900	0.08

[a] 1964-65 base year

TABLE 4-16. 1975 DIFFERENTIAL OPERATING COSTS OF OFA ON NEW AND EXISTING TANGENTIAL COAL-FIRED UTILITY BOILERS (Reference 4-108) (Net Heat Rate 9,500 Btu/kWhr, March 1975 Equipment Costs)

	New Plant Without Overfire Air	New Plant With Overfire Air	Recent Existing With Added Overfire Air	Older Existing Without Overfire Air	Older Existing With Added Overfire Air
Capital Costs $/kw	500.00	500.20	500.70	250.00	250.70
Annual Cap. Cost $	40,000,000[a]	40,016,000	40,056,000	20,000,000[b]	20,056,000
Annual Fuel Cost $	18,000,000[c]	18,000,000	18,000,000	9,000,000[d]	9,000,000
Labor & Maint.[e] $	8,100,000	8,100,000	8,100,000	8,100,000	8,100,000
Total Annual Cost[f] $	66,100,000	66,116,000	66,156,000	37,100,000	37,156,000
Electricity Cost[g] mils/kWhr	24.481	24.487	24.502	13.741	13.762
Increase — %	---	0.024	0.086	---	0.153
Increase — mils/kWhr[f]	---	0.006	0.021	---	0.021

Based on: [a] Annual fixed charge rate of 16% x 500 $/kW x 500,000 kW

[b] 16% x 250 $/kW x 500,000 kW

[c] 0.70 $/$10^6$ Btu coal cost x 5,400 hr/yr x 500,000 kW x 9,500 Btu/kWhr

[d] 0.35 $/$10^6$ Btu coal cost x 5,400 hr/yr x 500,000 kW x 9,500 Btu/kWhr

[e] Labor and maintenance cost of 3.0 mils/kWhr

[f] 5,400 hr/yr at 500 MW — 2,700 gWhr/yr

[g] Cost at plant bus bar; transmission and distribution not included

- Gas recirculation is more costly to implement than overfire air and requires additional fan power. In existing units, the need to reduce unit capacity to maintain acceptable gas velocities through the boiler convective sections may impose an additional penalty.
- In general, the cost of applying any of the control methods to an existing unit will be approximately 2 to 3 times that of a new unit design

4.2.10.2 Industrial Boilers

Cost data for combustion modifications on industrial boilers are virtually nonexistent, since research and development, including field testing and application of NO_x control methods to this equipment category, is in its early stages. Only the most broadly-based estimates are available. The most recent cost data are from a study in which a 5.1 MW (17.5 x 10^3 lb steam/hr) D-type watertube boiler was modified by adding staged air and flue gas recirculation capability (Reference 4-53). The windbox depth was increased and a second set of registers to control the recirculating flue gas was installed inside the extension. The cost of these modifications was estimated at $5,000; the current cost of new boilers of this type is about $60,000. The cost of a similar modification on other modern D-type boilers could be as high as $7,500, if the existing burner registers cannot be used.

Manufacturers of industrial boilers in the 88 MW (300 x 10^3 lb steam/hr) range and 1 million dollar cost category estimate that, in general, a staged air installation would add from 2 to 4 percent to the boiler's cost. For A-type boilers, the added cost would be about 2 percent, and for D-type boilers about 3 percent. Another booster air fan, if required, would increase the modification cost by about 1 percent (Reference 4-53).

In a recent study, costs for retrofitting an existing unit to accept flue gas recirculation were estimated (Reference 4-68). Approximate costs which include design, installation and equipment costs associated with the retrofit of FGR systems were, in 1975 dollars, $20,340 for a 3.51 MW firetube boiler and $21,190 for a 3.51 MW watertube boiler. However, these costs would be considerably less for a new boiler. Reference 4-68 estimates that for a new boiler of the size mentioned above, cost of including an FGR system will be about $6,900.

4.2.10.3 Internal Combustion Engines

There are few cost data for internal combustion engines, particularly for large (>375 kW or 500 hp) engines. Sufficient data exist, however, to give order of magnitude NO_x control costs for the following engine categories:

- Natural gas, dual fuel, and diesel fueled engines above 75 kW/cylinder (100 hp/cylinder)
- Small to medium (<75 kW/cylinder) diesel fueled engines
- Gasoline fueled engines (30 to 375 kW/cylinder)

Costs for large stationary engines can be estimated based on Reference 4-112 and information supplied to Reference 4-43. These costs, however, relate to emission reduction achieved by engines tested in laboratories rather than by field installations. Reference 4-94 indicates, nevertheless, that these data are representative.

Table 4-17 lists cost impacts for control techniques applied to large stationary engines. These cost impacts may be related to actual installations using baseline data presented in Table 4-18, which represent most applications. Basically, the controls involve an operating adjustment, however, derating and manifold air cooling require hardware additions. Also, derating is not a viable technique for existing installations unless additional units are added to satisfy total power requirements.

The impact of the control costs may vary considerably, given that:

- Standby (<200 hr/yr) application control costs are primarily a result of initial cost increases from emission control, whereas continuous service (>6,000 hr/yr) control costs are largely a function of fuel consumption penalties
- Controls which require additional hardware with no associated fuel penalty (e.g., manifold air-cooling) may be more cost effective in continuous service (>6,000 hr/yr), than operating adjustments which impose a fuel penalty (e.g., retard, or air-to-fuel change)
- The price of fuel can affect the impact of a control which incurs a fuel penalty. For example, a control which imposes a fuel penalty of 5 percent for both gas and diesel engines has more impact on the diesel fueled engine because diesel oil costs more (2.20/10^6 Btu compared to \$1.00/10^6 Btu for natural gas). This fuel impact may diminish if gas prices increase more rapidly than oil prices.

In contrast to the large stationary engines, more published cost data exist for smaller (<375 kW, 500 hp) gasoline and diesel engines which must meet State (California) and Federal emission limits for mobile applications. Stationary engines in this size range are versions of these mobile engines. Therefore, costs can be estimated based on a technology transfer from mobile applications to stationary service, keeping in mind that in some cases mobile duty cycles (variable

TABLE 4-17. COST IMPACTS OF NO_x CONTROLS FOR LARGE BORE ENGINES (Reference 4-43)

Control	Cost Impact
Retard	Increased fuel consumption
Air-to-fuel changes	Increased fuel consumption
Derate	Fuel penalty, additional hardware, and increased maintenance associated with additional units
Manifold air cooling	Increased cost to enlarge cooling system, and increased maintenance for cooling tower water treatment
Combinations of above	Initial, fuel, and maintenance
Control techniques	Increases as appropriate

TABLE 4-18. TYPICAL 1974 BASELINE COSTS FOR LARGE (>75 kW/Cylinder) ENGINES[a]

Costs	Gas	Dual Fuel	Diesel
1. Initial,[b] \$/kW	174	174	174
2. Maintenance, \$/kWhr	4×10^{-3}	4×10^{-3}	4×10^{-3}
3. Fuel and lube, \$/kWhr	10×10^{-3}	10×10^{-3}	23×10^{-3}
Total Operating, 2 + 3	14×10^{-3}	14×10^{-3}	27×10^{-3}

[a] Based on Reference 4-112 and information supplied to Reference 4-43 by manufacturers.

[b] Includes basic engine and cooling system.

load) can differ from stationary duty cycles (rated load). Thus, costs (e.g., fuel penalties) associated with a control technique used in a stationary application may vary from the mobile case. Control costs for automotive vehicles required to meet State and Federal emission limits are typical of the costs for small and medium gasoline and diesel fueled engines. However, more research is required to relate specific emission control reductions to initial and operating cost increases for stationary engine applications.

4.2.10.4 Gas Turbines

The most recent cost study of NO_x controls for gas turbines was performed by the EPA (Reference 4-69). Based on information presented in this study, the best available systems of emission reduction (considering costs) are wet systems, since these can be applied to turbines immediately at minimal cost impact. Although dry control techniques are preferable because of their potential simplicity, their complete development and application to large production turbines is still several years away. Cost considerations for dry methods are, therefore, not discussed.

Table 4-19, derived from Reference 4-69, shows the expected increase in installed turbine cost that results from using water injection to control NO_x to a proposed standard of 75 ppm. The impact varies from 0.8 percent for the 820 kW (1100 hp) standby unit to 7.1 percent for the unit that requires extensive water treatment equipment.

Table 4-20 summarizes the operating costs (in mils/kWhr), which would be incurred for 11 different simple cycle turbine plants meeting the proposed 75 ppm standard. This analysis was part of a cost model developed in the EPA report (Reference 4-69).

The first two units in Table 4-20, S-1 and S-2, differ only in the number of hours operated annually. S-1 operates 80 hours, and S-2 operates 200 hours per year. These units show the highest percentage impact in terms of the added costs per net kWhr of power generation. The low number of hours operated each year increases the cost of producing power, because fixed costs are spread over a relatively small base. The estimated impact in both cases was roughly 2.4 percent.

Cases S-3 and S-4 are 820 kW (1100 hp) units operating the same number of hours, respectively, as the smaller 261 kW units. These units can use exactly the same water purification system as the smaller units. Since the costs of producing power independent of the water injection system are identical, the percentage impact is much less, decreasing to less than 1 percent.

Case I-1 represents a normal, single shift gas turbine application. The unit is operated 2,000 hours per year and is slightly oversized, which negates any benefits that might be derived

TABLE 4-19. IMPACT OF NO_X EMISSION CONTROL ON THE INSTALLED 1975 CAPITAL COST OF GAS TURBINES (Reference 4-69)

Application	Installed Cost (1000$)		% Increase
	Without Controls	With Controls	
A. Standby			
1. 261 kW (350 hp)	56.6	58.0	2.4
2. 820 kW (1,100 hp)	177.9	179.3	0.8
B. Industrial			
1. 3 MW (4,000 hp) — typical	352.8	366.8	4.0
2. 3 MW — offshore	352.8	379.8	7.1
C. Utility			
1. 66 MW	9,900.0	10,070.0	1.7

TABLE 4-20. 1975 COSTS FOR WATER INJECTION, MILLS/KWHR
(Reference 4-69)

Item	Standby				Industrial			Utility				Offshore Drilling Platform
	S-1	S-2	S-3	S-4	I-1	I-2	I-3	U-1	U-2	U-3	U-4	
Unit Size	261 kW	261 kW	820 kW	820 kW	3 MW	3 MW	3 MW	66 MW	66 MW	66 MW	66 MW	3 MW
Hours of Operation Per Year	80	200	80	200	2,000	2,000	3,000	200	500	2,000	8,000	8,000
Annualized Fixed Costs	13.65	5.46	4.32	1.73	0.48	0.12	0.12	2.58	1.03	0.26	0.06	0.23
Operating Cost of Water Treatment	0.46	0.46	0.37	0.37	0.10	0.10	0.10	0.11	0.11	0.11	0.11	0.35
Water for Injection	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	–
Energy Penalty	0.51	0.51	0.51	0.51	0.43	0.43	0.43	0.34	0.34	0.34	0.34	0.43
Water Transport Costs	–	–	–	–	–	–	0.64	–	–	–	–	–
Output Enhancement	–	–	–	–	–	0.09	0.09	–	–	–	0.11	0.09
Total	14.63	6.44	5.21	2.62	1.02	0.57	1.21	3.04	1.49	0.72	0.41	0.92
Baseline Costs	611.29	264.79	611.29	264.79	43.77	32.53	35.53	180.00	85.45	38.20	26.39	32.53
Percent Impact	2.39	2.43	0.85	0.99	2.32	1.75	3.71	1.69	1.75	1.88	1.56	2.83

T-116

from improved unit output. For Case I-2, also a baseload turbine, a credit was taken for the improved capacity of the unit.

The highest cost impact was recorded in Case I-3, which represents a remote turbine application in an arid climate in which water must be transported 50 miles at a cost of $0.02 per gallon. The impact in such cases, including water storage facilities, is approximately a 3.7 percent increase in the average cost of generating power. Since water injection results in a slight increase in the power output capacity of the unit, a credit of 0.05 mills per kWhr was taken for the output enhancement. A credit for enhanced output was also taken in the U-3 unit, since it is baseloaded. In all four utility cases, the impact is less than 2 percent per kWhr.

Initially, it was thought that the offshore drilling platform would show the highest cost impact. The unit was assumed to use sea water to fuel the water purification system, which involved a substantial increase in the capital and operating cost of the system. The installed cost of the water treatment equipment was $27,000, compared to $14,000 for an onshore application. Despite these higher costs, the availability of water offset the costs associated with transporting water to the remote gas compressing station application (I-3). The total cost of water injection for the offshore platform was 0.92 mills/kWhr compared to 1.21 mills/kWhr for the remote site.

In summary, the resulting estimates showed that, except for standby units, the total change in costs probably falls within the range of 0.4 to 1.5 mills per kWhr for turbines used in industrial and utility applications. This cost is equivalent to about a 2 percent increase in operating costs. Control costs for standby units were much higher, ranging from 2 to 14 mills per kWhr, because they are used less. The cost is equivalent to approximately a 2.5 percent increase in operating costs.

4.2.10.5 Residential Heating Systems

Advanced low-NO_x burners in new furnace units are the best options for NO_x control in space heating equipment. A Blueray unit has been commercially available since 1974 and has been widely tested in field installations, while a Rocketdyne unit is undergoing field demonstration preparatory to certification and potential commercialization. With proper maintenance, both units offer NO_x reduction potentials of 50 percent or greater and fuel savings of 5 percent or more, relative to standard units. Using these low-NO_x units in new houses and replacing obsolete conventional units in existing houses would decrease residential NO_x emissions nationwide, offsetting the potential emissions increase from population growth, for several decades.

The 1975 cost, less installation, of the Blueray unit was $550 (Reference 4-113), compared to conventional warm air furnaces which range from $300 to $500. The added cost of the low-NO_x

unit may be justified, however, since fuel savings result from the improved thermal efficiency. Differential costs for the Rocketdyne unit are comparable.

The prospects for cost-effective NO_x control in existing space heating units are not promising. There are no modifications which significantly decrease NO_x emissions. Furnace tuning and, if required, burner head replacement are strongly recommended for reduction of carbon monoxide and smoke and for improving unit efficiency, but these modifications have little impact on NO_x. Furnace tuning (cleaning, nozzle replacement, leak detection, sealing and burner adjustment) costs a minimum of $40 for the average residential unit, while head replacement costs an additional $25, less installation. This servicing is usually cost effective since it saves fuel and increases safety of operation.

4.2.10.6 Industrial Process Heating

Currently, there is very little application of NO_x control to direct industrial process heating equipment. EPA's Industrial Environmental Research Laboratory (RTP) is sponsoring a field test program to identify the potential for NO_x control in a diversity of process furnaces, ovens, kilns, and heaters. The program, scheduled for completion in 1979, will provide the data to evaluate alternate control options.

4.3 FUEL DENITRIFICATION

To meet future NO_x emission standards for stationary sources, fuel NO_x may have to be reduced to levels even lower than those produced by combustion modifications. "Fuel NO_x" emission reduction from combustion equipment can be achieved with combustion modifications, clean fuel burning, or by extracting the fuel bound organo-nitrogen prior to burning (fuel denitrification). This section describes the state of the art and the potential application of denitrification of oil and coal.

4.3.1 Oil Denitrification

Current technology for denitrification derives from pretreating fuel to remove sulfur. Heavy-oil cracking (HOC), hydrodesulfurization (HDS), and coking are the three major refinery processes to desulfurize fuel oil. Hydrodesulfurization is the most widely used and will be the only process discussed here. HDS produces a very low sulfur content liquid fuel and, at the same time, reduces nitrogen by about 20 to 40 percent. Table 4-21 shows the performance and the reducing effect on the nitrogen content of the fuel of one such HDS process.

Stringent federal and state regulations for sulfur dioxide emissions prohibit the direct combustion of high sulfur Middle Eastern and South American crude oils. Therefore, virtually all imported oils are refined for partial removal of sulfur before they are used. Presently two residuum hydrodesulfurization techniques exist:

- Vacuum gas-oil hydrodesulfurization (VGO)
- Residuum desulfurization (RDS)

The VGO process, also known as the indirect method, treats only the vacuum gas-oil product of the vacuum distillation process with catalytic hydrodesulfurization, achieving at most 30 to 35 percent desulfurization. Since with this process the yields of low sulfur oil are relatively small and since only vacuum gas-oil can be treated, the residuum desulfurization technique or direct method was developed. The advantage of residuum desulfurization is that it can catalytically desulfurize residuum from the atmospheric distillation process.

Several feedstock desulfurization processes are used by major oil companies to produce very low sulfur solid, liquid, and gaseous fuels. The overall desulfurization (HDS) and denitrification (HDN) chemical reactions involved are (Reference 4-114):

$$\begin{Bmatrix}\text{organo-sulfur compound}\\ \text{organo-nitrogen compound}\end{Bmatrix} + H_2 \xrightarrow{\text{catalyst}} \text{hydrocarbons} + \begin{Bmatrix}H_2S\\ NH_3\end{Bmatrix}$$

Hydrogen sulfide and ammonia are easily removed with presently available technology.

TABLE 4-21. HYDRODESULFURIZATION PERFORMANCE OF THE GULF PROCESS

Average of run properties
for 375F+ product

Gulf HDS Process	Feed[a]	Desulfurized residual fuel oils		
		Type III	Type IV	Improved Type III
Sulfur, Wt %	3.8	0.3	0.1	0.3
Nitrogen, Wt %	0.21	0.13	0.11	0.13
Nickel, ppm	15	1.1	0.2	1.8
Vanadium, ppm	45	0.8	0.1	3.3
Gravity, API	16.6	24.5	26.0	25.4
Carbon residue (Rams), Wt%	8.3	3.3	2.2	3.3
Heat of Combustion, Btu/lb		19,250	19,350	19,300
Pour Point, F		20	0	25
Viscosity, SUV at F				
110	3,500	435	320	375
210	160	55	53.5	58

[a] Kuwait 650F+ charge to HDS

Sulfided cobalt-molybdenum on alumina or nickel molybdenum on alumina are typical catalysts in these processes. HDS and HDN occur simultaneously at suitable temperature and pressures, but the reactions interact with each other in ways which are little understood. Satterfield (Reference 4-114) has conducted an extensive program to uncover the interactions of catalytic desulfurization and denitrification. Thiophene and pyridine were used as model compounds because they represent some of the less reactive organo-sulfur and organo-nitrogen compounds. The maximum conversion of pyridine observed in Satterfield's work was 50 percent, whereas thiophene reached 100 percent conversion. Figure 4-8 presents the results for HDN of pyridine alone on a $NiMo/Al_2O_3$ catalyst and in a number of mixtures with thiophene. Up to 655K, increases in reactor temperature increase the percent conversion of pyridine to ammonia. However, as temperature is increased beyond 655K, the percent converted is decreased.

The effect of thiophene on HDN is two-fold. Below 600K the presence of sulfur compounds inhibits the HDN reaction, but above 600K the presence of thiophene enhances the HDN reaction. This enhancement was attributed to the presence of H_2S in the reaction, which prevents the initially sulfided catalyst to become rapidly desulfided.

Large deposits of shale in the U.S. are seen as a promising source of further crude oil, but shale oil has a characteristically high concentration of nitrogen, ranging from 1.5 to 2.8 percent by weight. More than two thirds of the nitrogen in crude shale oil is present in the form of quinolines (pyridines) and indoles (pyrolles). Frost, et al. (Reference 4-115), studied the effect of reactor temperature and pressure on the degree of fuel denitrification from crude shale oil using the catalytic hydrogenation method. Nitrogen contents of the hydrotreated products ranged from 0.005 to 1.59 weight-percent from the original 2.18 percent in the untreated crude. Frost demonstrated that denitrification of residual oils can be increased from 20 to 40 percent removal to complete denitrification by progressively increasing the severity of the hydrogenation process, either by increasing temperature or pressure or by changing to a more active catalyst.

As severity increases so does hydrogen consumption. Figure 4-9 shows the percent denitrification as a function of hydrogen consumption. As the amount of hydrogen needed to denitrify the fuel increases, the operating cost of the process also increases significantly. The majority of recently reported hydrodesulfurization production costs (which produce 20 to 40 percent denitrification) are between $5.00 and $10.70 per kiloliter of oil ($0.80-1.70/bbl) (Reference 4-116). The cost of hydrogen is a major part of this total, contributing as much as $3.80/kl ($0.60/bbl) for a process using approximately 170 nm^3 of hydrogen per kiloliter of feed (1000 scf H_2/bbl feed). In addition, the higher pressures associated with increased process severity increase the initial investment cost,

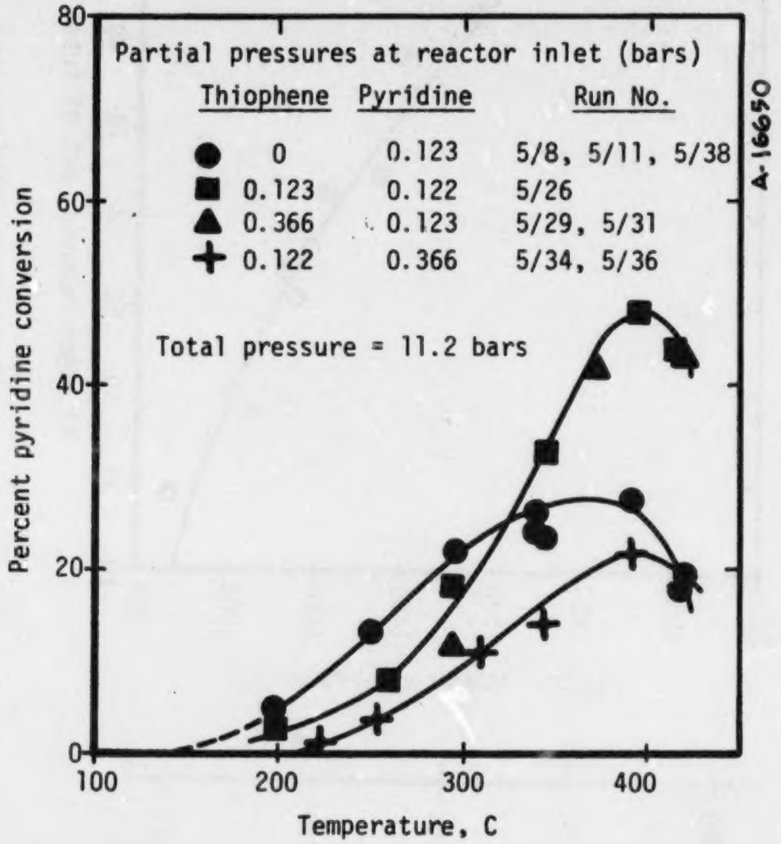


Figure 4-8. Pyridine HDN with $NiMo/Al_2O_3$ catalyst.

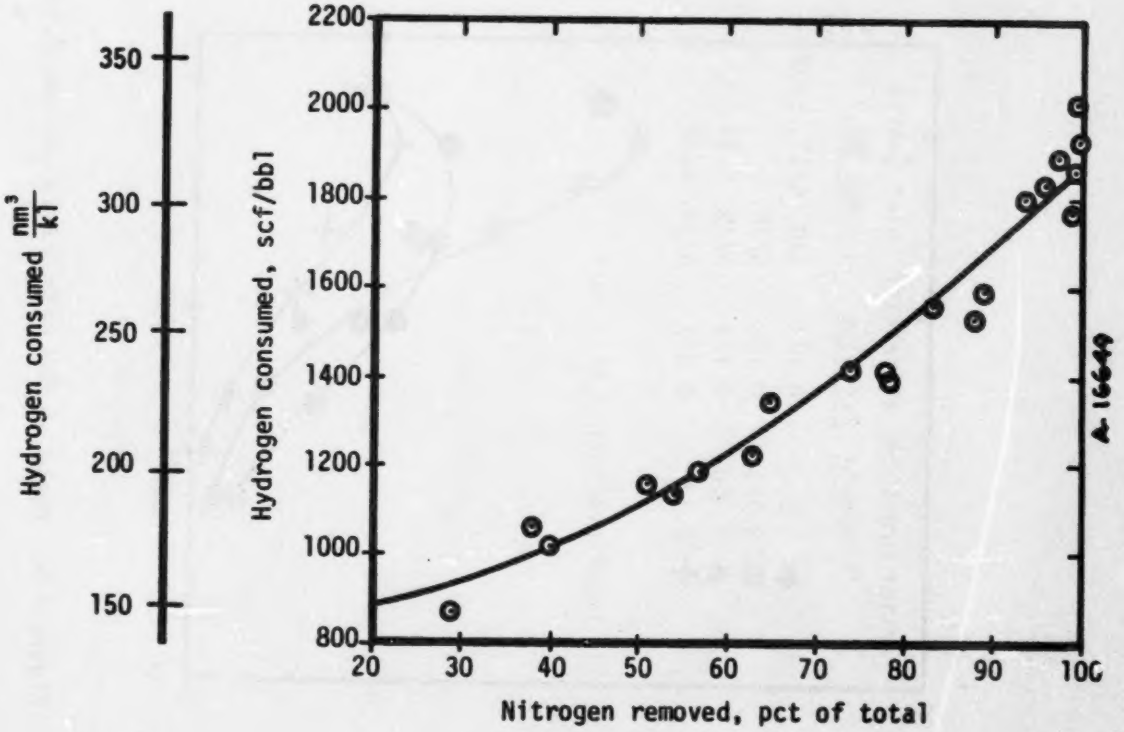


Figure 4-9. Hydrogen consumption versus nitrogen removal (Reference 4-116).

since more expensive equipment is needed (Reference 4-117). Hydroprocessing is undergoing rapid technological development, as demands for low-sulfur and low-nitrogen residual oil increase.

Other denitrification methods are also being investigated. Guth and Diaz (Reference 4-118) have patented an oxidation process to desulfurize and denitrify petroleum oils; the process has been successfully operated at the pilot scale. In the Guth and Diaz process, the fuel nitrogen is oxidized to the extent that the resultant compounds exhibit preferential solubility characteristics in a solvent, usually methanol. In some cases, pretreatment of the oil to remove active groups which cause undesirable side reactions or removal of low-sulfur fractions prior to the oxidation step are necessary to increase the efficiency of the process. The oil is separated from the resultant solution in a gravity separator. The extraction of the oxidized nitrogen compounds can be carried out simultaneously or in batches.

One possible difficulty with this process is that some oils tend to react nonselectively during the oxidation step and form undesirable polymers and coke. This problem can be alleviated by preheating the feed oil to 475 to 660K (300 to 600F) for 2 to 20 hours to permit the reactive groups in the oil to combine with other hydrocarbons and thus become less active. Recent tests show that up to 93 percent denitrification was achieved with distillate oils and 45 percent with residual oils. This method is currently still under investigation; full scale experimentation is expected in the near future.

This denitrification and desulfurization process is particularly attractive since it does not require hydrogen and it operates at low temperatures and pressures. Capital costs range from $4.50 to $11.30 per liter per hour ($30 to $75 per bbl/day) using distillate oil; process operating costs range from $0.50 to $1 per day (Reference 4-119). Costs were not given for residual oils, since the Guth-Diaz process does not denitrify all residuals. One major application of this process is in a small refinery (133 kl/hr or 20,000 bbl/day capacity); the capital investment would be relatively small compared with conventional hydroprocessing.

4.3.2 Coal Denitrification

Besides coal gasification and liquefaction, alternative processes which decrease the sulfur content of coal are presently being investigated. Some of these are:

- Solvent refined coal (SRC)
- Meyers process
- Hydrothermal desulfurization

However, none of the above processes has shown any promise in removing fuel bound nitrogen from coal.

Solvent refined coal is produced by dissolving raw coal in a solvent, separating the ash from the coal by filtration, and reconstituting the coal from the solvent. The reconstituted coal is free of water, low in sulfur, very low in ash, and sufficiently low in melting point that it can be handled as a fluid, if desired. Its heat content is higher than that of coal at a uniform value of 37,177 kJ/kg (16,000 Btu/lb), regardless of the original coal from which it was prepared.

Unfortunately, the nitrogen content of solvent refined coal is not reduced. The results of two SRC tests conducted by Pittsburg and Midway Coal Mining Company (Reference 4-120) in which the nitrogen content was essentially unchanged are as follows:

TABLE 4-22. SOLVENT REFINED COAL TESTS

	Feed Composition	Product Composition #1	Product Composition #2
% C	64.76	87.50	87.32
% H	4.36	5.23	5.11
% S	4.94	0.882	0.944
% N	1.85	2.040	1.909
% O	8.33	4.17	4.58
% Ash	15.76	0.179	0.133

Increases can be attributed to errors in material balance procedures and to the fact that ash was removed. Because of its significantly lower sulfur content and improved heating value SRC has great potential for future use as a utility fuel. Its impact on "fuel NO_x" emissions will be insignificant since the fuel nitrogen content remains unchanged. However, NO_x emissions on a basis of lb/MBtu may decrease due to the higher heating value of solvent refined coal.

In the Meyers process, the pyritic sulfur in the coal is removed by a reaction with ferric sulfate in a solution containing ferric and ferrous sulfate and sulfamic acid, the elemental sulfur product is extracted with an organic solvent. Analysis on the product coal showed that the nitrogen content was essentially not affected by the Meyers process (References 4-121 and 4-122).

E. P. Stambaugh of Battelle Memorial Institute (BMI) has also developed a process for removing sulfur from high-sulfur coal. The Battelle Hydrothermal Coal Process (BHCP) involves heating a coal slurry and a chemical leachant at moderate temperature and pressure to selectively extract the sulfur and some of the ash from the coal. As with other coal pretreatments, hydrothermal treatment does not extract the nitrogen (References 4-123 and 4-124).

In summary, with present technology, only liquid fuels can be denitrified. High temperature, high pressure catalytic hydrodesulfurization is the most widely accepted way to denitrify residual oil.

No new improved technology has been investigated on a full scale basis, although some new processes have been developed and tested with pilot scale facilities.

The present HDN processes have several disadvantages that contribute to the ever increasing cost of desulfurization and denitrification. First, it is costly to use hydrogen to remove sulfur and nitrogen. Hydrogen must be produced by pyrolyzing hydrocarbon materials or through combustion of hydrocarbons to form carbon monoxide, which is subsequently reacted catalytically with water at high temperature. Second, the process requires a heterogeneous catalyst. The surface of the solid catalyst tends to become fouled (particularly when residual oils are desulfurized), making the process inefficient or not feasible with some residual fuels. And thirdly, the process requires high temperatures and high pressures, which necessitates expensive equipment. The nitrogen content of coal is not easily reduced unless the coal is first converted to a liquid fuel (i.e., coal liquefaction). Presently, no coal desulfurization processes have any significant effect on fuel nitrogen.

4.4 FUEL ADDITIVES

Fuel additives have been used for many years as agents to reduce soot and ash deposits on heat transfer surfaces and to minimize the corrosion effects of these deposits. Fuel additives have contributed to improved equipment performance and maintenance, but recently, fuel additives have been investigated as possible aids in reducing nitrogen oxide emissions from small steam generators, gas turbines, and IC engines.

Additives can theoretically reduce NO_x emissions through one or a combination of the following effects (Reference 4-125):

- Catalytic reduction or decomposition of NO to N_2
- Reduction of local concentration of atomic oxygen
- Reduction of flame temperature through increased thermal radiation and dilution
- Delay of ignition timing in IC engines
- Decrease of fuel/air mixing through a change in spray fluid dynamics

A number of investigators have experimented with numerous fuel additives in order to reduce NO_x emissions. Shaw (Reference 4-125) investigated approximately 70 additives in a jet-fueled gas turbine combustor. The organometallic additives, cobalt, iron, copper, and manganese were added to the fuel in 0.5 percent by weight concentrations. They acted as reducing and decomposing catalysts and reduced NO_x by 15 to 30 percent.

McCreath (Reference 4-126) investigated the effect of additives on NO_x emissions from diesel engines. He found that both isoamyl nitrate and ditertiary butyl peroxide, which reduced the ignition delay, could reduce the nitrogen oxides content of the exhaust gas by 15 to 18 percent using 0.15 moles of additives per liter of diesel fuel. Other organometallic compounds in concentrations of 1 percent by volume reduced NO_x by 16 percent in laboratory burners (Reference 4-127).

One of the more comprehensive studies on fuel additives was reported by Martin, Pershing, and Berkau (Reference 4-128). Over 200 currently marketed additives were tested on diesel fuel and burned in an experimental furnace. No NO_x reduction was reported; instead, some of the nitrogen containing additives increased NO_x emissions. In continuation of their work (Reference 4-129), four of the most widely publicized materials (Trimex, Pace, KAP, and Glo-Klen) were tested in a 40 kW (54 hp) firebox-firetube packaged boiler firing residual oil. The additives were blown into the primary combustion zone, but the effect on NO_x emissions under all conditions investigated was insignificant, and particulate emissions increased significantly. A good state-of-the-art review of combustion additives may be found in Reference 4-130.

One problem with additives is since liquid and solid fuel additives contain large quantities of solids and inerts, including potentially corrosive salts or toxic metals, they can create a severe air pollution hazard or can be otherwise deleterious to equipment and surroundings. Also, at \$2 to \$20 dollars per kilogram, fuel oil additives can be very expensive (Reference 4-128).

Another potential use of fuel additives is in combination with well established NO_x control techniques; they suppress some of the negative effects that the control techniques have on other pollutants and combustion equipment performance. For example, for large multiburner boilers firing residual oils and coal, off-stoichiometric combustion through staged firing and low excess air are well known combustion modification techniques with definite NO_x reduction effects. The degree of implementation of these techniques is limited by adverse side effects such as

- Localized reducing atmosphere leading to heat transfer surface corrosion especially with high sodium and high vanadium fuels
- Decreased convective heat transfer leading to loss in superheater steam temperatures
- Fouling and corrosion of air heaters
- Increased hydrocarbon particulate matter causing boiler efficiency loss

Additives with high metallic concentrations which act as oxidation-promoting catalysts can help alleviate these adverse side effects, thus, theoretically allowing increased flexibility of NO_x reducing combustion modifications (References 4-131 and 4-132). This concept has yet to be investigated, but could result in lower NO_x emissions. Some of the benefits of fuel additives toward NO_x reduction are listed in Table 4-23. Most of these additives are used in utility and large industrial boilers.

T-166

TABLE 4-23. FUEL ADDITIVES WITH POSSIBLE PERIPHERAL BENEFITS TO NO_x CONTROL TECHNIQUES IN BOILERS

Additive Function	Possible Benefits to NO_x Control Techniques	Applicable Fuel	Manufacturer Suggested Addition Rate
Combustion improver	Increased flexibility of: Low excess air Off stoichiometric combustion Flue gas recirculation Alternate fuel usage Combination of the above	Distillate and residual oils, coal, mixed fuels	Oil — 0.01 to 0.1 mol % Coal — 0.01 to 0.02 wt %
Corrosion inhibition	Increased flexibility of: Low excess air Off stoichiometric combustion Alternate fuel usage Combination of the above	Residual oil and coal	Oil — 0.01 to 0.1 mol % Coal — ~0.005 wt %
Antifouling	Increased flexibility of: Low excess air Off stoichiometric combustion	Residual oil and coal	Oil — 10 to 1,000 ppm Coal — 0.01 to 0.02 wt %
Soot, smoke and carbon particulate reduction	Increased flexibility of: Low excess air Flue gas recirculation Off stoichiometric combustion	Distillate and residual oil, coal	Oil — 0.92 to 0.96 g/l Coal — ~0.04 wt %

In summary, the results of recent studies on fuel additives for NO_x control have been mixed. In some cases additives had a significant effect on NO emissions, while in other studies they did not. Overall, the use of additives for controlling NO_x is not attractive due to added cost, serious operational difficulties and the presence of the additives as pollutants in the exhaust gas. However, it has been proposed that some fuel additives may provide a peripheral benefit to NO_x control, by allowing increased flexibility in applying combustion modification techniques. The potential for adverse environmental impacts due to this practice will be considered in the NO_x E/A.

4.5 ALTERNATE AND MIXED FUELS

One alternate NO_x reduction method involves the use of a fuel with a low-nitrogen content (to suppress fuel NO_x) and/or one that burns at a lower temperature (to reduce thermal NO_x). Fuels with relatively small amounts of sulfur and chemically-bound nitrogen are referred to as "clean" fuels, and are most desirable from an environmental point of view.

Natural gas firing (a "clean" fuel) is an attractive NO_x control strategy; it produces no fuel NO_x and it provides flexibility for implementing combustion modification techniques. However, since natural gas is becoming increasingly scarce, many large users are having to switch to coal.

At present, coal contributes only about 18 percent of the energy utilized in the U.S. annually, but the production of coal has been projected to increase 72 percent from 56.1 Tg (618×10^6 tons) in 1974 to 94.4 Tg ($1,040 \times 10^6$ tons) in 1985 (Reference 4-133). Since the direct combustion of coal adversely affects the environment, there is a tremendous research effort directed toward making cleaner fuels not only from coal, but also from other sources. A brief discussion on combustion experience with these fuels and on the prospects for low NO_x emissions follows.

4.5.1 Western Coals

The direct combustion of western subbituminous coals in large steam generators generally produces lower NO_x emissions. Three mechanisms are responsible for lower NO_x emissions: first, western coals, in general, contain less bound nitrogen than eastern coals on a unit heating value basis; second, the excess O_2 in a steam generator burning western coal can be maintained at very low levels; and third, the high moisture content of western coal produces lower flame temperatures.

NO_x emissions for an 88 MW (130,000 lb steam/hr) industrial boiler firing pulverized western coal at baseline conditions were 24 percent lower than for eastern coals (Reference 4-48). NO_x emissions remained unchanged when firing western coal in stokers. However, the slope of the NO_x vs. excess O_2 curve for a water-cooled vibrating grate stoker firing western coal (Wyoming Bighorn) was 12 ppm/percent excess O_2, compared to 35 ppm/percent excess O_2 for eastern coal (Kentucky Vogue).

Some specific problems associated with burning low-sulfur, high moisture content coals in combustion equipment designed for higher quality coals are listed below (Reference 4-134):

- Poor ignition
- Reduced boiler load capacity
- Increased carbon loss
- Boiler fouling
- High superheat steam temperature
- Flame instability
- Increased boiler maintenance
- Reduced boiler efficiency
- Reduced collection efficiency of electrostatic precipitator (ESP)

4.5.2 Low-Btu Gas

NO_x emission data are sparse for low-Btu gas, defined here as having a net heating value of 3.0 to 5.9 MJ/nm^3 (75 to 150 Btu/scf). The data available from combustion equipment firing low-Btu gas show that NO_x emissions from a 1.3 MW (4.5×10^6 Btu/hr) furnace firing 100 percent low-Btu gas were below 10 ppm (Reference 4-135). The same furnace burning 100 percent natural gas produced 60 ppm NO. The lower NO_x emissions, ranging from 0 to 10 ppm for NO, when burning low-Btu gas were attributed to both decreased peak temperature and decreased combustion intensity. The NO_x emissions were obtained using an experimental combustor can and air preheat temperatures up to 1070K (1,250F) to simulate gas turbine conditions. Compared to natural gas and No. 2 oil, a 50 to 65 percent reduction in NO_x emissions for a 70 to 80 MW gas turbine firing low-Btu gas was projected (Reference 4-136). The fuel nitrogen cleanup of this low-Btu gas involves removing mainly NH_3 (also 30 to over 50 percent of the gas is N_2). The level of NH_3 in the gas depends on the particular coal and gasification process used.

4.5.3 Medium- and High-Btu Synthetic Gas

Medium-Btu gas (having a heating value of about 11.8 MJ/nm^3 or 300 Btu/scf) is being considered for direct firing, after cleanup, in utility boilers located at the gasifier site with only minor modifications to current state-of-the-art combustion equipment (Reference 4-137). Another possibility being evaluated is burning this gas in oxygen-fired steam generators. Since bulk oxygen is needed for the gasifier, the additional cost to supply the steam generator should not be prohibitive, but this type of combustion process will require considerable boiler design changes.

215

Medium-Btu gas and oxygen should produce combustion temperatures greater than 2790K (4,000F), but the total NO_x production should still be insignificant since molecular and fuel nitrogen are absent (Reference 4-138).

Medium-Btu gas can be upgraded to high- (35.4 to 39.4 MJ/nm^3 or 900 to 1,000 Btu/scf) Btu gas. High-Btu gas is indistinguishable from natural gas, except it may form fuel NO_x if any bound nitrogen (NH_3, HCN, etc.) is present.

4.5.4 Synthetic Oil from Coal

The physical and chemical properties of synthetic oil are a function of the coal properties and processing conditions. Direct combustion of the oil without pretreatment represents an environmental problem, since the oil typically has a high nitrogen content (0.7 to 1.8 percent by weight). This percentage of nitrogen corresponds to 400 to 1,000 ppm of NO_x emissions, based on 40 percent fuel nitrogen conversion, and would require the use of combustion modifications to reduce NO_x to acceptable levels (Reference 4-135).

4.5.5 Coal-Oil Slurry

The need to stretch domestic oil supplies has renewed government interest in using coal-oil slurries for direct combustion in steam-generating equipment. Coal-oil slurries could be made environmentally acceptable, depending on the quantities of pollutants present in the coal and oil and the percentages of coal and oil used in the slurry. A General Motors program investigating the use of coal-oil slurries concluded that emissions of oxides of nitrogen increase with increasing coal concentration and decreasing coal particle size (Reference 4-139). The quantity of coal that can be used is limited by slurry stabilization, combustion equipment performance, and environmental aspects (Reference 4-140).

4.5.6 Methanol

Currently, the synthesis of methane from natural gas is the major source of methanol. But due to the shortage of natural gas, future production will have to come from synthetic gas generated from coal. Baseline NO_x emissions from the combustion of methanol in an experimental hot wall furnace system were reported at 50 to 70 ppm, compared to 240 to 300 ppm for distillate oil. With flue gas recirculation, the NO_x emissions from methanol combustion were reduced to 10 ppm or 15 percent of the baseline level (Reference 4-141). The hot wall experimental furnace also showed a 20 percent increase in stack heat loss (SHL), compared to SHL of 14 percent for distillate oil (based on 115 percent theoretical air at a 475K stack temperature). In gas turbines 74 percent less NO_x was produced using methanol, compared to distillate oil. Turbine efficiency levels increased by 6 percent due to higher inlet temperatures.

Methanol is generally a potentially attractive fuel for use in area sources where clean fuels are necessary for environmental reasons. Its current high price does not justify its use.

4.5.7 Water-Oil Emulsions

Residual oil emulsions with up to 35 percent water were fired in a Scotch packaged boiler rated at 700 kW (2.5 x 10^6 Btu/hr). NO_x emissions were not reduced from the baseline level (oil only) for a given stoichiometric ratio. This was attributable to the high nitrogen content of the residual oil; emulsions affect only thermal NO_x (Reference 4-142). In the same experiments, because of the reduction in smoke levels, the boiler could be operated at a lower stoichiometric ratio, which reduced the NO_x emissions.

Emulsions have a definite NO_x reduction potential when distillate oil is used (Reference 4-143). NO_x emission levels from emulsions with approximately 50 mass percent water in distillate oil approached the levels obtained from methanol combustion (Reference 4-135).

In conclusion, the feasibility of alternate fuel firing as a NO_x control option is contingent in part on the cost trade-off between synthetic fuel production and the total control costs for NO_x, SO_x and particulates in conventional coal firing. There is preliminary evidence that gasification may be more costly than flue gas cleaning of conventional systems.

4.6 ALTERNATE CONCEPTS

The recent domestic shortages in conventional clean fuels, the rising cost of oil and gas, and above all, the need to limit the pollutant emissions resulting from burning fossil fuels have accelerated the development of alternate energy concepts. Some concepts (e.g., catalytic combustion, fluidized bed combustion, and gasifier combined cycle) are being developed for their potential not only to increase system efficiency, but also to reduce total system emissions. Other alternate concepts (e.g., repowering, high temperature gas turbines) are being developed mainly to increase efficiency and reduce fuel consumption.

Catalytic combustion systems and high temperature gas turbine developments are well underway. Within the next decade catalytic combustion may find use in gas turbines and space heating; high temperature gas turbines are expected to be commercially available in the late 1980's.

Fluidized bed combustion and combined cycle development are also in progress. Several organizations are building pilot-scale fluidized bed combustion units, and commercialization of fluidized bed combustors may take place during the late 1980's.

Another alternate concept, repowering, is a method of upgrading existing power plants to make them more competitive at today's fuel prices or to make more efficient use of present fuel contracts; prospects for widespread use of this concept are presently uncertain.

4.6.1 Catalytic Combustion

Catalytic combustion refers to combustion occurring in close proximity to a solid surface which has a special (catalytic) coating. A catalyst accelerates the rate of a chemical reaction, so that substantial rates of burning should be achieved at low temperatures, avoiding the formation of thermal NO_x. Moreover, the catalyst itself serves to sustain the overall combustion process, thereby minimizing the stability problems (Reference 4-144 and 4-145). However, the overall success of a catalytic combustion system in reducing CO and HC to low levels is a function of both heterogeneous and gas phase reactions; surface reactions alone appear to be unable to achieve the desired low levels.

Emissions from catalytic combustion experiments have typically been: $NO_x < 2$ ppm, HC ≈ 4 ppm, and CO = 10 to 30 ppm. Both gaseous and distillate fuels have been used and combustion efficiencies above 95 percent have been obtained (Reference 4-145).

The catalyst bed temperature must be held below 1810K (2800F) to minimize the formation of NO_x. At high temperatures, above 1275K (1,830F), catalyst activity decreases. At present, catalytic combustors are limited by the bed temperature capability. Excess air can be used to lower the bed temperature; but the use of excess air is unattractive since it also reduces thermal efficiency (except in gas turbines). Further research is underway to consider other systems, such as catalyst bed cooling, exhaust gas recirculation, and staged combustion to maintain a low bed temperature.

Recent tests evaluated the applicability of catalytic combustors for gas turbines. Test fuels used were No. 2 distillate oil and low Btu synthetic coal gas, for a range of pressure, temperature, and mass flow conditions. Test results show that the catalyst bed temperature profile at the bed exit was very uniform for low Btu gas, but not as uniform for No. 2 oil. Exceptionally low emissions (2 to 3 ppm NO_x, 20 to 30 ppm CO) were achieved for both fuels, and unburned hydrocarbons (HC) were less than 1 ppm (Reference 4-146). However, much additional work is needed before catalytic combustion can be applied to gas turbines in the field.

Catalytic combustion has been demonstrated to be effective in lowering emissions of pollutants such as NO_x, CO, and HC, but at present, catalytic combustors are limited by the catalyst bed temperature capability. Various government agencies and private industries are developing catalysts that will withstand high temperatures, retain high catalyst activity, and last longer. Catalyst combustion systems are also under development. It appears that during the next 5 to 10 years, catalyst combustion concepts may be incorporated into new gas turbine and residential and commercial heating designs.

4.6.2 Fluidized Bed Combustion

In its simplest form, a fluidized bed combustor (FBC) contains a bed of granular material such as coal, ash and sand or limestone. Hot air is blown through a distributor in the base of the combustor vessel to "fluidize" the solid particles (i.e., the particles are supported by the gas stream and in rapid motion relative to each other). This process creates a bed which has the appearance of a boiling liquid and exhibits many fluid-like properties.

For coal-fired FBCs, if the temperature of the bed remains above the combustion temperature of the coal, the FBC process will be self-sustaining. The bed temperature is generally in the range of 1075 to 1275K (1,500F to 1,900F) and the combustor may be at atmospheric pressure (AFBC) or it may be pressurized (PFBC) (References 4-147 and 4-148). Energy added to the bed by the combustion process is removed, in a fluidized bed boiler, by the boiler tubes, heat losses through the walls, and the gas and solids leaving the bed.

A 30 MW AFBC pilot plant began operation in late 1976 (Reference 4-149). Pressurized systems are still being tested, with a pilot plant planned for the early 1980's.

NO_x emissions in fluidized bed systems depend on the equipment; significant emissions have been found in some reactors (Reference 4-32). NO_x emissions also depend, though weakly, on coal particle size, the type and amount of sulfur acceptor, and the amount of excess air. However, emission levels from pressurized fluidized bed combustors are significantly less than from atmospheric combustors, probably due to greatly increased NO_x decomposition rates at elevated pressures.

NO_x levels in most coal-fired fluidized bed experiments conducted at atmospheric pressure are on the order of 300 to 500 ppm (Reference 4-150). NO_x emissions from a pressurized FBC, even at 100 percent excess air, are well below the current standards of 300 ng NO_2/J (0.7 lb/10^6 Btu). Results of 160 ng/J (0.41 lb/10^6 Btu) have been reported (Reference 4-149). The principle disadvantages of FBCs, are (1) potentially large amounts of solid waste (the sulfur acceptor material) and (2) heavy particulate loadings in the flue gas. The feasibility of an FBC for power generation will depend on developing

- Efficient methods for regeneration and recycling of the dolomite/limestone materials used for sulfur capture and removal
- Complete combustion through flyash recycle or an effective carbon burnup cell
- A hot-gas particulate removal process to permit use of the combustion products in a combined cycle gas turbine without excessive blade erosion

4.6.3 Repowering

Repowering adds a combustion turbine to an existing steam plant, providing additional capacity at lower initial capital costs and lower energy costs than other means available to a utility.

Repowering includes: (1) steam turbine repowering, in which gas turbines and new heat recovery boilers are added to an existing steam electric generating plant; (2) boiler repowering in which gas turbines are added to the existing steam generating facilities for power generation, requiring the conversion of existing conventional boilers to heat recovery type boilers; and (3) gas turbine repowering in which a steam generating plant is added to an existing gas turbine plant (References 4-151 and 4-152).

Depending on the system and power needs, repowering of existing facilities offers the following advantages:

- There is no need to acquire and develop a new plant site
- Repowering generally requires smaller increments of investment, saving on fixed charges since major investment on new plants is deferred
- Repowering improves heat rate, which lowers fuel consumption
- The environmental impact is reduced, with improving schedules for environmental and site related approvals
- For boiler and steam turbine repowering, there is no increase in cooling water requirements
- Gas turbines may be operated independently as peaking units, which provides greater plant flexibility

References 4-151 and 4-152 describe in detail the application of repowering to boiler, gas turbine, and steam generating plants; savings in capital and operating costs are anticipated. Under contract from the Electric Power Research Institute, Westinghouse Electric Corporation is evaluating repowering conventional steam power plants without replacing the boiler. The present use of repowering is very limited. It may see extensive use in the 1980's if significant increases in generating capacity are needed.

4.6.4 Combined Cycles

Combined cycles may, in the long term, reduce emissions of sulfur oxides, nitrogen oxides, particulate matter, and waste heat while generating power at efficiencies higher than conventional fossil- and nuclear-fueled steam stations (Reference 4-153).

The combined gas and steam turbine system consists of a gas turbine using a coal-derived fuel, which exhausts into an unfired waste-heat-recovery boiler. At the gas turbine inlet, the most economical large-scale steam system would operate at 16.5 MPa (2,400 psig) with 810K (1,000F) throttle steam and 810K (1,000F) reheat temperatures. In this system, roughly 66 percent of the power would be generated by the gas turbine; the remaining 34 percent would be generated by the steam boiler system (Reference 4-154).

Combined cycle efficiency improves significantly as the gas turbine inlet temperature is increased. At turbine inlet temperatures of 1,478K (2,200F), an efficiency improvement of 2 percentage points per 56K (100F) increase in turbine inlet temperature is found.

A feasibility analysis on combined cycle systems was conducted by Solar, a division of International Harvester. The analysis showed that with the presently available steam turbines and boilers, the efficiencies would not be sufficient to justify a combined cycle. Therefore, Solar is developing new small steam boiler and turbine designs which are expected to be available by 1980. Applications of combined cycles include pipeline, offshore platform, marine, and small electric utilities (Reference 4-155).

The current status of combined cycles has been reviewed by Papamarcos (Reference 4-156). According to Papamarcos, before combined cycles are commercialized, efficient fuel conversion processes and high temperature gas turbines that can use coal-derived fuels must be developed. He estimates that these developments will take place in some 15 to 20 years, and current ERDA projections concur with his estimate.

4.6.5 High Temperature Gas Turbines

The efficiency and power output of a gas turbine increase significantly as the inlet temperature is increased. Turbines that are used in the field are limited to 1075 to 1275K (1,500 to 1,800F) by the strength of the turbine materials. A gas turbine firing stoichiometrically at temperatures above 1,920K (3,000F) would increase power output by more than 150 percent, and thermal efficiency relative to conventional units. However, performance gains at higher temperatures can be realized only if losses caused by the cooling system can be kept to a minimum (Reference 4-157).

The current practice of turbine cooling, using air bled from the compressor, requires bringing the cooling air to the required pressure. The power output is reduced, since a substantial portion of the cooling air reenters the gas downstream of at least one of the bucket stages. Moreover, once the cooling air reenters the gas, it decreases the gas temperature, which reduces the energy available to the turbine and to the heat recovery system in the exhaust stack (Reference 4-156).

Because a high temperature gas turbine has higher potential for increased efficiency and specific output, various methods which allow high temperatures are being considered. These are:

- Water cooling
- Advanced air cooling
- Steam cooling
- Substitution of ceramic compounds

In current programs, ERDA is funding four turbine manufacturers (General Electric, Westinghouse, Curtiss-Wright, and United Technology) to develop a high temperature turbine technology (HTTT). And more recently, EPRI has funded a HTTT program at GE. The main emphasis of these programs is to develop the high temperature portion of the gas turbine for firing temperatures of 1,700K (2,600F) and possibly up to 1,920K (3,000F).

Efficiency will be improved and specific costs will be reduced over the next 5 to 10 years in high temperature gas turbine technology. Leading gas turbine manufacturers are designing high temperature gas turbines that can be operated up to 1,920K (3,000F) with cooling of the blades. To cool the blades, water cooling appears to be the most attractive method.

4.7 FLUE GAS TREATMENT

Flue gas treatment (FGT) processes reduce NO_x emissions from combustion sources through either decomposition or oxidation/absorption. Flue gas treatment has potential for use with combustion modifications when very high removal efficiencies are required. Much of the developmental work in FGT has been done in Japan (References 4-61, 4-107, and 4-158 through 4-164).

FGT is currently applied to only a few commercial gas- and oil-fired boilers. Research in the United States in developing flue gas treatment has been minimal, since needs have been uncertain. However, the recent emphasis of stationary source NO_x emission controls has encouraged further development of FGT in the United States (Reference 4-165).

FGT processes can be divided into two main categories: dry processes and wet processes. Dry processes reduce NO_x by catalytic reduction and operate at about 525K (700F). Wet systems remove NO_x by oxidation followed by scrubbing, and operate at 315 to 325K (100F to 120F). Table 4-24 summarizes the available wet and dry processes.

TABLE 4-24. SUMMARY OF FGT PROCESSES

Process	Process Description	Comments
Dry Processes:		
Hitachi shipbuilding process	CO and H_2 in the presence of catalysts selectively reduce NO_x. CuO, Fe_2O_3, Cr_2O_3, NiO, Co_3O_4, MnO, V_2O_5, and Pt are various catalysts that can be used.	About 98% reduction can be obtained. No wastestreams are produced. Major drawback is that this process requires catalysts which have the selective behavior for promoting faster CO/H_2 — NO reaction than CO/H_2 — O_2 reaction.
Selective reduction with ammonia	NH_3 and O_2 in the presence of catalysts, reduce NO_x to NO. Pt, Vanadia, Fe-Cr oxide mixtures, Mo, Cu-Pb are some of the catalysts used.	Above 90% reductions are achieved. This process removes NO_x and SO_x simultaneously. Careful temperature control (480K-590K) is necessary.
Hydrogen sulfide process	Selective catalytic reduction of NO_x in the presence of H_2S (gas phase)	NO_x reductions up to 98% are obtained. Removes NO_x and SO_x simultaneously. Condensation of sulfur causes catalyst to lose activity. 100% use of H_2S is important since it is toxic.
Char (Bergbau - Forschung - Foster Wheeler Process)	A dry adsorption process. SO_2, O_2 and H_2O in flue gas are adsorbed in the char pores. Adsorbed SO_2 reacts with O_2 and H_2O to form H_2SO_4 which is retained by char pellets. NO_x is also absorbed by char.	High removal rate (95%) for SO_x; only 40-65% of NO_x is removed. SO_2 can be reduced directly to elemental sulfur.
CuO (Shell/UOP flue gas desulfurization process)	CuO reacts with SO_2 in the presence of O_2 at 670K to yield $CuSO_4$	Effective for SO_x removal (90%), removes 60-70% of NO_x. Low pressure drop through parallel flow sorbent bed. Easy regeneration of sorbent. No particulate interference.
Wet Processes:		
Sodium scrubbing (Fujikasui process)	Gaseous ClO_2 oxidizes NO to NO_2. NO_2 scrubbed with $NaClO_2$.	Over 90% NO_x reductions. Low cost and easy operation, but requires waste water treatment because of by-product effluents. NaCl, $NaNO_3$, and Na_2SO_4.
Alkali permanganate (MON process)	NO_x and SO_2 absorbed and oxidized with alkali permanganate to form alkali nitrate and sulfate	Over 90% NO_x removal and virtually all of SO_2. No waste material is produced. Scrubbing agent (alkali KOH) is expensive.
Sodium-potassium permanganate (Nissan process)	Two-step method. NO_x is removed with NaOH. Off-gas is oxidized with permanaganate and NO_2 absorbed with NaOH.	High removal rate (90%) of NO_x. Easy and flexible operation. Byproduct potassium nitrate is a fertilizer; however, waste water treatment is required.
Alkali scrubbing (Shinko process)	NO_x is scrubbed first with liquid NaOH; off-gas is sent to second scrubber — a packed granular alumina reactor sprayed with NaOH and $NaClO_2$	Over 95% of NO_x removed with products of $NaNO_3$, NaCl and gaseous ClO_2. However, $NaClO_2$ is expensive.

(Continued on page 4-94)

T-153

TABLE 4-24. Concluded

Process	Process Description	Comments
Chiyoda Thoroughbred 102	NO is oxidized by ozone and air. Aqueous H_2SO_4 with an iron catalyst act as scrubbing agents.	About 60% NO_x removal efficiency. Simple and easy operation. However, a relatively low efficiency NO_x removal process and requires wastewater treatment and expensive ozone. Additional equipment needed to remove ozone from the exit gas stream.
Alkali scrubbing (Kyowa Kako)	NO_x is first scrubbed with NaOH, off-gas is oxidized with H_2O_2, and then washed with alkaline hydrogen sulfide or alkali sulfide	High NO_x removal (from 4,000 ppm down to 50 ppm), but requires waste water treatment and sludge disposal
Sodium sulfite scrubbing	Sodium sulfite reduces NO_x to N_2	Over 90% NO_x reduction. Absorbs NO directly, thereby eliminating costly oxidizing agents. Large flowrates and excess O_2 hinders NO_x reduction.
MHI (Mitsubishi Heavy Industries)	Ozone is injected into flue gas; NO_x is oxidized to N_2O_5; this is reduced to N_2 by reacting with $CaSO_3$ in the circulating scrubber liquor	Simple process, high (over 90%) NO_x removal. Does not produce waste water. However, production of ozone and the use of high concentration of HNO_3 are costly.
Kureha reduction	NO_x is scrubbed using 3 scrubbers: sodium acetate, limestone slurry, and sodium sulfate and sulfite containing acetic acid and a catalyst	Removes NO_x and SO_x simultaneously. Produces useful gypsum and no waste water streams. However, it is a complex process; and costly.
Kawasaki magnesium	Magnesium hydroxide slurry is used as a scrubbing agent to remove NO_x	Removes both NO_x and SO_x. Produces marketable gypsum and calcium nitrate. Process is complex and costly.
Chisso ammonia scrubbing	NO_x is removed using ammoniacal solution containing a soluble catalyst	About 60 to 80% of NO_x is removed. Produces byproduct ammonium sulfate. Possibility exists for plume formation.
Kobe steel process	Calcium chloride solution containing $Ca(OCl)_2$ is used to reduce NO_x	High NO_x removal efficiency is attained. Scrubber corrosion is a problem.

4.7.1 Dry FGT Processes

Dry processes are mainly applied to flue gas streams derived from burning gaseous fuels. Each process developer utilizes different catalysts, catalyst supports, and bed configurations. Dry processes are basically simple, require little space, and require no reheating of the tailgases.

Among the many dry process variations, selective catalytic reduction using ammonia has been successful in treating combustion flue gases for removal of NO_x. However, the large amounts of ammonia required would increase the consumption of natural gas considerably. In addition, any ammonia left in the flue gases may combine with the SO_3/SO_2 to produce a visible plume, and by-products, such as ammonium-bisulfate, which are corrosive to boiler tubes.

Molecular sieve adsorption is another dry FGT process identified as a possible NO_x control technique; however, it was developed primarily for noncombustion applications, such as nitric acid manufacturing plants. Molecular sieve adsorption is not applicable to the water-containing effluents from combustion sources due to preferential adsorption of moisture and a resultant loss of active sites (Reference 4-166).

4.7.2 Wet FGT Processes

Wet FGT processes utilize more complex chemistry than dry processes (Reference 4-165). In the wet processes, strong oxidants such as ozone or chlorine dioxide are used to convert the relatively inactive NO in the flue gas to NO_2 or N_2O_5 for subsequent absorption. Thus, most of the wet processes create by-products such as nitric acid, potassium nitrate, ammonium sulfate, calcium nitrate, and gypsum.

Wet FGT processes use either liquid or gaseous chemicals to complete the required NO oxidation. Liquid phase oxidation requires extensive liquid/gas contact to absorb the inactive NO, thus the use of liquid phase oxidation processes is limited, because of the large size and pressure drop of the NO absorber.

Using ozone or chlorine dioxide to oxidize NO in the gas stream prior to the scrubber appears to be a more successful approach. Chlorine dioxide is expensive, however, and using it introduces the problem of disposing of chloride-containing liquid discharges. Ozone is also quite costly, requiring a great deal of electrical energy to produce. Also, where ozone is utilized, additional equipment is required for removal of excess ozone from the final gas stream. Thus, oxidant cost is likely to be prohibitive for flue gases with high NO_x concentrations.

Cost estimates for FGT processes are presented in Table 4-25, but these estimates are only preliminary since most FGT processes are in the developmental stages in the U.S. Compared to combustion modifications, FGT is considerably more expensive, but is capable of greater NO_x reduction. Increased costs result from both higher capital costs and costs of chemicals and catalysts.

In general, the dry FGT techniques used in Japan can probably be applied to gas- and oil-fired sources in the U.S. However, more pilot scale research and field tests are needed before full implementation of dry processes is possible. Also, the applicability of dry processes to coal-fired sources remains to be determined. Wet processes are less well developed and costlier than dry FGT processes, however, wet processes have the potential to remove NO_x and SO_x simultaneously. Again, more field tests are needed to determine the costs, secondary effects, reliability, and waste disposal problems. Flue gas treatment holds some promise as a control technique for use when high NO_x removal efficiencies are necessitated by stringent emission standards.

Ammonia injection, discussed in Section 4.2.9, is a competitive process which may prove more cost effective for NO_x control. Ammonia injection is not applicable to simultaneous NO_x/SO_x reduction, however.

4.8 EVALUATION AND SUMMARY

Table 4-26 summarizes current and emerging NO_x control technology for the major source categories. These results show that current technology is dominated by combustion process modification. Emerging technology is also centered around combustion modifications. Other approaches, such as flue gas treatment, may be used in the 1980's to augment combustion modification if required by stringent emission standards.

The level of combustion modification control available for a given source depends largely on the importance of that source in regulatory programs. Utility boilers have been the most extensively regulated and accordingly, the technology is the most advanced. Available technology ranges from operational adjustments such as low excess air and biased burner firing to inclusion of overfire air ports or low-NO_x burners in new units. Some adverse operational impacts have been experienced with use of combustion modification on existing equipment. In general these have been solved through combustion engineering or by limiting the degree of control application. With factory-installed controls on new equipment, operational problems have been minimal.

The technology for other sources is less well developed. Control techniques shown effective for utility boilers are being demonstrated on existing industrial boilers. Here, as for utility boilers, the emphasis in emerging technology is on development of controls applicable to new unit design. Advanced low-NO_x burners and/or advanced off-stoichiometric combustion techniques are the

TABLE 4-25. 1974 COST ESTIMATES FOR COMBUSTION FLUE GAS TREATMENT PROCESSES (Reference 4-160)

Process Type	Process	Application	Estimated Capital Costs	Estimated Operating Costs (mill/kWhr)
Wet	Chiyoda Thoroughbred 102	Oil-fired boiler	$70-90/kW	3-4
Wet	Sumitomo (Moretana)	Oil-fired boiler	$70-100/kW	7
Dry: selective catalytic reduction	Sumitomo	Gas-fired boiler	$40/kW	1.2
	Sumitomo	Oil-fired boiler	$93/kW	No Data
Dry: selective catalytic reduction	Hitachi	Oil-fired boiler	$60/kW	No Data

TABLE 4-26. SUMMARY OF NO_x CONTROL TECHNOLOGY

Equipment/ Fuel Category	Current Technology				Emerging Technology		Comments
	Available Control Technique	Achievable NO_x Emission Level ng/J ($lb/10^6$ Btu)	Estimated Differential Annual Cost	Operational Impact	Near Term 1977-1982	Far Term 1983-2000	
Existing coal-fired utility boilers	LEA + OSC (OFA, BOOS, BBF); new burners	260-300 (0.6 - 0.7)	20-30¢/kW	Possible increase in corrosion & slagging & carbon in flyash	Advanced low NO_x burners	Ammonia injection; flue gas treatment	Ammonia injection, FGT potential supplement to CM if needed
New coal-fired utility boilers	LEA + OFA; new burners	215-260 (0.5 - 0.6)	10-20¢/kW	No major problem with tangential design; other designs now coming online	Low NO_x burners advanced staging concepts	Optimized burner firebox design; fluidized bed combustion; ammonia injection	Same as above
Existing oil-fired utility boilers	LEA + OSC + FGR; load reduction	110-150 (0.25 - 0.35)	$1-2/kW	Possible flame instability; boiler vibration	Low NO_x burners; oil denitrification	Ammonia injection; flue gas treatment	No new units; emission levels are limit of current technology
Existing gas-fired utility boilers	LEA + OSC + FGR; load reduction	65-85 (0.15 - 0.2)	$1-2/kW	Possible flame instability; boiler vibration	Low NO_x burner	Ammonia injection; flue gas treatment	No new units; emission levels are limit of current technology
Oil-fired industrial watertube boilers	LEA + OSC (OFA, BOOS, BBF)	85-130 (0.2 - 0.3)	1.4-1.8¢/(kg/hr)^a	~1% increase in fuel consumption; flame instability; boiler vibration (retrofit)	Low NO_x burners; OFA in new unit designs; oil denitrification	Optimized burner/firebox design; ammonia injection	Current technology still being developed

(Continued on page 4-99)

T-155

TABLE 4-26. Continued

Equipment/ Fuel Category	Current Technology				Emerging Technology		Comments
	Available Control Technique	Achievable NO_x Emission Level ng/J (lb/10^6 Btu)	Estimated Differential Annual Cost	Operational Impact	Near Term 1977-1982	Far Term 1983-2000	
Stoker-fired industrial watertube boilers	LEA + OFA	150-190 (0.35 - 0.45)	1.8-2.34/ (kg/hr)[a]	Possible ~1% increase in fuel consumption; corrosion; slagging of grate (retrofit)	Inclusion of OFA in new unit design	Fluidized bed combustion; ammonia injection	Current technology still being developed
Gas-fired industrial watertube boilers	LEA + OSC (OFA, BOOS, BBF)	86-130 (0.2 - 0.3)	1.4-1.84/ (kg/hr)[a]	~1% increase in fuel consumption; flame instability; boiler vibration (retrofit)	Low NO_x burners; OFA in new unit design	Optimized burner/firebox design; ammonia injection	Current technology still undergoing development
Industrial firetube boilers	LEA + FGR; LEA + OSC	65-110 (0.15 - 0.25)	7-14¢/ (kg/hr)[a]	~1% increase in fuel consumption; flame instability (retrofit)	Low NO_x burners; OFA or FGR in new unit design	Optimized burner/firebox design	Development continuing on current technology
Gas turbines	Water, steam injection	110-150 (0.25 - 0.35)	$1-2/kW	~1% increase in fuel consumption; affects only thermal	Advanced combustor designs for dry NO_x controls	Catalytic combustion; advanced can designs	Current technology widely used

(Continued on page 4-100)

TABLE 4-26. Concluded

Equipment/ Fuel Category	Current Technology				Emerging Technology		Comments
	Available Control Technique	Achievable NO_x Emission Level ng/J ($lb/10^6$ Btu)	Estimated Differential Annual Cost	Operational Impact	Near Term 1977-1982	Far Term 1983-2000	
Residential furnaces	Low NO_x burner/ firebox design (oil)	25-40 (0.06 - 0.1)	\$0.14-0.29/ kW (4-8 x 10^8 BTUPH)	~5% decrease in fuel consumption	Advanced burner/firebox design (gas & oil)	Catalytic combustion	Current technology still being tested
IC engines	Fine tuning; changing A/F	1,070-1,290 (2.5 - 3.0)	\$0.70-2.00/kW (\$0.5-1.5/ BHP)	5-10% increase in fuel consumption; misfiring; poor load response	Include moderate control in new unit design	Advanced head designs	Technology still being tested
Industrial process furnaces	LEA	85-210 (0.2 - 0.5)	Unknown	Unknown	Low NO_x burners; development of external controls (FGR, OSC) on retrofit basis	Possible inclusion in new unit design	Control development in preliminary stages

[a] kg/hr steam produced

most promising concepts. This holds true for the other source categories as well. The R&D emphasis for gas turbines, warm air furnaces and reciprocating IC engines is on developing optimized combustion chamber designs matched to the burner or fuel/air delivery system. Control development for the diverse types of industrial process equipment is in a preliminary stage. To date, only minor operational adjustments have been tried.

Table 4-27 summarizes the status and effectiveness of general control techniques. As noted above, a number of techniques are applicable for operational adjustments and hardware modifications of either new or existing units. The trend, however, is toward new burners or off-stoichiometric combustion in combination with low excess air. This approach yields a higher degree of control, is more cost effective and minimizes adverse operational impacts.

The final column on Table 4-27 evaluates controls with respect to their treatment in the NO_x E/A. This evaluation will be discussed further in Section 7.2 where priorities are set on near- and far-term source/control applications. This evaluation is also used to scope the evaluation of incremental impacts due to NO_x controls discussed in Section 6.

The information in this section initiates the process engineering studies of major source categories in the NO_x E/A. The preliminary control evaluation has shown the need for more data in the following areas:

- Current control technology
    - Impact on operation/performance
    - Economics/control costs
    - Environmental impact
- Emerging control technology
    - New operating data as it becomes available
    - Economic estimates
    - Environmental concerns

The seven process engineering studies to be performed in Task 7247 will focus on these requirements, while many of the data gaps will be filled under Task 7245 or through related ongoing programs. Since most of the current technology has been demonstrated on utility and large industrial boilers, the first two studies to be performed will cover these categories.

One especially important area where more accurate data are needed is in differential control costs. During the process engineering studies, all cost procedures will be standardized and a

T-156

TABLE 4-27. OVERALL EVALUATION OF NO_x CONTROL TECHNIQUES

Control Technique	Existing Applications	Effectiveness	Operational Impact	Projected Applications	Control Evaluation for NO_x E/A Effort
Low excess air (LEA)	Retrofit and new utility boilers; some use in industrial boilers	10% to 30% for thermal and fuel NO_x	Increase in efficiency; amount limited by smoke or CO at very low EA	Widespread use for efficiency increase; incorporate into advanced designs all sources	Primary emphasis near-term and far-term applications (all sources); combined with OSC & burner mods for far-term appl.
Flue gas recirculation (FGR)	Retrofit use on many gas- and oil-fired utility boilers; demonstrated on industrial boilers	20% to 50% for thermal NO_x; no effect on fuel NO_x	Possible flame instability; increased vibration	Possible use in new industrial boiler designs	Primary emphasis near-term applications large boilers; possible far-term industrial boiler application
Off stoichiometric combustion (OSC) incl. OFA, BOOS, BBF	New and retrofit use on many utility boilers; demonstrated on industrial boilers	20% to 50% for thermal and fuel NO_x	No major impact with new design; potential for flame instability, efficiency decrease, increased corrosion (coal-fired) with retrofit	Widespread use in large boilers; incorporate into advanced designs	Primary emphasis near-term and far-term applications all sources
Load reduction	Some retrofit use on gas and oil utility boilers; enlarged fireboxes on new coal units	0% to 40% for thermal NO_x	Decrease in efficiency and power output; limited by spare capacity and smoke formation	Enlarged fireboxes used in new unit design; limited use for retrofit	Secondary emphasis near-term applications (boilers); combined with OSC or burner mods for far-term appl.
Burner modifications	New and retrofit use on utility boilers; demonstrated on residential furnaces	30% to 60% for thermal and fuel NO_x	No major impact with new design; retrofit use constrained by firebox characteristics	Incorporate into advanced designs utility, industrial boilers, residential, process furnaces, GT; combine with OSC	Primary emphasis near- and far-term applications all sources

(Continued on page 4-103)

TABLE 4-27. Continued

Control Technique	Existing Applications	Effectiveness	Operational Impact	Projected Applications	Control Evaluation for NO_x E/A Effort
Water, steam injection	Widely used for gas turbines	30% to 70% for thermal NO_x	Slight decrease in efficiency: limited by CO formation; power output increases	Use in new gas turbines; possible use in process furnaces	Primary emphasis near-term applications, gas turbines; possible far-term industrial process application
Reduced air preheat (RAP)	Widespread use in large turbocharged IC engines	10% to 40% for thermal NO_x	Slight decrease in efficiency, increase power output	Continued use in IC engines	Secondary emphasis
Ammonia injection	Demonstrated on oil- and gas-fired industrial boilers	40% to 70% for thermal and fuel NO_x	Retrofit use limited; possible adverse environmental impact	Use in large boilers in some areas (1980's)	Primary emphasis far-term application to large boilers; evaluate impact with coal firing
Fuel denitrification	Oil denitrification accompanies desulfurization for some large boilers	10% to 40% for fuel NO_x	No adverse effects	Use of oil denitrification in large boilers as supplement to CM tech.	Secondary emphasis; evaluate as alternate fuel
Fuel additives	Fuel additives for NO_x not used	Generally ineffective for direct NO_x reduction	Byproduct emissions formed	Additives for corrosion, fouling, particulate, smoke, etc. can provide increased flexibility with CM tech. on large boilers	Secondary emphasis; consider impact of additives
Alternate and mixed fuels	Combustion of low nitrogen alternate fuels being demonstrated	Varies	Varies	Combined cycles and residential and commercial heating systems	Secondary emphasis far-term application; evaluate differential impact of fuel switching; transfer results of other E/A's.

(Continued on page 4-104)

TABLE 4-27. Concluded

T-156

Control Technique	Existing Applications	Effectiveness	Operational Impact	Projected Applications	Control Evaluation for NO_x E/A Effort
Catalytic combustion	Only tested in experimental combustors	>90% for thermal NO_x	Requires clean fuel; combustors limited by catalyst bed temp. capability	Gas turbines and residential and commercial heating systems	Primary emphasis far-term applications; compare impact to burner mods, alternate fuels
Fluidized bed combustion	Tested in pilot/prototype combustors	20% to 50% for fuel NO_x (pressurized FBC)	Requires sulfur acceptor	Combined cycle, utility boilers, industrial boilers (1980's)	Transfer results from FBC E/A; compare impact to combustion modifications, conventional combustion
Flue gas treatment (FGT)	Used in Japan on large boilers	40% to >90% for fuel and thermal NO_x	Requires temp. controls, catalyst, scrubbing soln., or oxidizing agent; possible adverse environmental impact	Possible supplement to CM for utility and large industrial boilers (1980's)	Secondary emphasis; transfer results of other studies to compare impact to combustion mods

common basis will be established for detailed costing of NO_x control techniques. Thus, a more accurate comparison of cost effectiveness between control options can be made. The first step in future work on Task 7247 will be to focus on establishing this and other standardized procedures.

REFERENCES FOR SECTION 4

4-1. Environment Reporter, State Air Laws (2V.) Bureau of National Affairs, Inc., Washington, D.C.

4-2. Zeldovich, J., "The Oxidation of Nitrogen in Combustion and Explosions," Acta Physiochen URSS, (Moscow), Vol. 21, 1946 p. 4.

4-3. Bowman, C. T. and D. J. Seery, "Investigation of NO Formation Kinetics in Combustion Processes: "The Methane - Oxygen - Nitrogen Reaction" in Emissions from Continuous Combustion Systems, W. Cornelius and W. G. Agnew, eds, Plenum, 1972.

4-4. Bartok, W., et al., "Basic Kinetic Studies and Modeling of NO Formation in Combustion Processes," AIChE Symposium Series No. 126, Vol. 68, 1972.

4-5. Halstead, C. J. and A. J. E. Munro, "The Sampling, Analysis, and Study of the Nitrogen Oxides Formed in Natural Gas/Air Flames," Company Report, Shell Research et al., Egham, Surrey, U. K., 1971.

4-6. Thompson, D., et al., "The Formation of Oxides of Nitrogen in a Combustion System," presented at 70th National AIChE Meeting, Atlantic City, N.J., 1971.

4-7. Lange, H. B., "NO_x Formation in Premixed Combustion: A Kinetics Model and Experimental Data," presented at 64th Annual AIChE Meeting, San Francisco, 1971.

4-8. Sarofim, A. F. and J. H. Pohl, "Kinetics of Nitric Oxide Formation in Premixed Laminar Flames," 14th Symposium (International) on Combustion, The Combustion Institute, Pittsburgh, 1973.

4-9. Iverach, D., et al., "Formations of Nitric Oxide in Fuel-Lean and Fuel-Rich Flames," ibid., 1973.

4-10. Wendt, J. O. L. and J. M. Ekmann, "Effect of Fuel Sulfur Species on Nitrogen Oxide Emissions from Premixed Flames," Comb. Flame, Vol. 25, 1975.

4-11. Malte, P. C. and D. T. Pratt, "Measurement of Atomic Oxygen and Nitrogen Oxides in Jet-Stirred Combustion," 15th Symposium (International) on Combustion, The Combustion Institute, Pittsburgh, 1975.

4-12. Mitchell, R. E. and A. F. Sarofim, "Nitrogen Oxide Formation in Laminar Methane Air Diffusion Flames," presented at the Fall Meeting, Western State Section, The Combustion Institute, Palo Alto, Ca., 1975.

4-13. Bowman, C. T., "Non-Equilibrium Radical Concentrations in Shock Initiated Methane Oxidation," 15th Symposium (International) on Combustion, The Combustion Institute, Pittsburgh, 1975.

4-14. Fenimore, C. P., "Formation of Nitric Oxide in Premixed Hydrocarbon Flames," 13th Symposium (International) on Combustion, The Combustion Institute, Pittsburgh, 1971.

4-15. MacKinnon, D. J., "Nitric Oxide Formation at High Temperatures," J. APCA, Vol. 24, No. 3, March 1974, pp. 237-239.

4-16. Heap, M. P., et al., "Burner Criteria for NO_x Control; Volume I — Influence of Burner Variables on NO_x in Pulverized Coal Flames," EPA 600/2-76-061a, NTIS-PB 259 911/AS, March 1976.

4-17. Bowman, C. T., et al., "Effects of Interaction Between Fluid Dynamics on Chemistry or Pollutant Formation in Combustion," in Proceedings of the Stationary Source Combustion Symposium; Volume I — Fundamental Research, EPA 600/2-76-152a, NTIS-PB 256 320/AS, June 1976.

4-18. Shaw, J. T. and A. C. Thomas, "Oxides of Nitrogen in Relation to the Combustion of Coal," presented at the 7th International Conference on Coal Science, Prague, June 1968.

4-19. Pershing, D. W., et al., "Influence of Design Variables on the Production of Thermal and Fuel NO from Residual Oil and Coal Combustion," AIChE Symposium Series, No. 148, Vol. 71, 1975, pp. 19-29.

4-20. Sarofim, A. F., et al., "Mechanisms and Kinetics of NO_x Formation: Recent Developments," presented at 65th Annual AIChE Meeting, Chicago, November 1976.

4-21. Martin, G. B., and E. E. Berkau, "An Investigation of the Conversion of Various Fuel Nitrogen Compounds to Nitrogen Oxides in Oil Combustion," presented at 70th National AIChE Meeting, Atlantic City, N.J., August 1971.

4-22. Habelt, W. W. and B. M. Howell, "Control of NO Formation in Tangentially Coal-Fired Steam Generators," in Proceedings of the NO_x Control Technology Seminar, EPRI SR-39, February 1976.

4-23. "Air Quality and Stationary Source Emission Control," U. S. Senate, Committee on Public Works, Serial No. 94-4, March 1975.

4-24. Pohl, J. H. and A. F. Sarofim, "Fate of Coal Nitrogen During Pyrolysis and Oxidation," in Proceedings of the Stationary Source Combustion Symposium; Volume I — Fundamental Research, EPA 600/2-76-152a, NTIS-PB 256 320/AS, June 1976.

4-25. Heap, M. P., et al., "The Optimization of Burner Design Parameters to Control NO_x Formation in Pulverized Coal and Heavy Oil Flames," in Proceedings of the Stationary Source Combustion Symposium; Volume II — Fuels and Process Research and Development, EPA 600/2-76-152b, NTIS-PB 256 321/AS, June 1976.

4-26. Pohl, J. H. and A. F. Sarofim, "Devolatilization and Oxidation of Coal Nitrogen," presented at 16th International Symposium on Combustion, M.I.T., August 1976.

4-27. Blair, D. W., et al., "Devolatilization and Pyrolysis of Fuel Nitrogen from Single Coal Particle Combustion," 16th Symposium (International) on Combustion, Cambridge, Mass., 1976.

4-28. Pershing, D. W., "Nitrogen Oxide Formation in Pulverized Coal Flames," PhD Dissertation, University of Arizona, 1976.

4-29. Axworthy, A. E., Jr., "Chemistry and Kinetics of Fuel Nitrogen Conversion to Nitric Oxide," AIChE Symposium Series, No. 148, Vol. 71, 1975, pp. 43-50.

4-30. Axworthy, A. E., et al., "Chemical Reactions in the Conversion of Fuel Nitrogen to NO_x," in Proceedings of the Stationary Source Combustion Symposium, Volume I, EPA 600/2-76-152a, NTIS-PB 256 320/AS, June 1976.

4-31. Pershing, D. W., and J. O. L. Wendt, "The Effect of Coal Combustion on Thermal and Fuel NO_x Production from Pulverized Coal Combustion," presented at Central States Section, The Combustion Institute, Columbus, Ohio, April 1976.

4-32. "Control Techniques for Nitrogen Oxide Emissions from Stationary Sources — Draft Second Edition," Aerotherm TR-76-222, Acurex Corporation/Aerotherm Division, Mountain View, CA, October 1976.

4-33. Barr, W. H., and D. E. James, "Nitric Oxide Control — A Program of Significant Accomplishments," ASME 72-WA/Pwr-13.

4-34. Barr, W. H., et al., "Retrofit of Large Utility Boilers for Nitric Oxide Emissions Production — Experience and Status Report."

4-35. Crawford, A. R., et al., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions for Utility Boilers," Exxon Research and Engineering Co., EPA 650/2-74-066, NTIS-PB 237 344/AS, June 1974.

4-36. Crawford, A. R., et al., "The Effect of Combustion Modification on Pollutants and Equipment Performance of Power Generation Equipment," in Proceedings of the Stationary Source Combustion Symposium; Volume III — Field Testing and Surveys, Exxon Research and Engineering Co., EPA 600/2-76-152c, NTIS-PB 257 146/AS.

4-37. Blakeslee, C. E., and H. E. Burbach, "Controlling NO_x Emissions from Steam Generators," C. E. Inc., APCA 72-75, 65th Annual Meeting of Air Pollution Control Association, June 18-22, 1972.

4-38. Blakeslee, C. E., and H. E. Burbach, "NO_x Emissions from Tangentially-Fired Utility Boilers, Part II, Practice," AIChE Symposium Series No. 148, Vol. 71, 1975.

4-39. Selker, A. P., "Program for Reduction of NO_x from Tangential Coal-Fired Boilers, Phase II and IIa," EPA 650/2-73-005a and b, NTIS-PB 245 162/AS and NTIS-PB 246 889/AS, June 1975.

4-40. Bartok, W., et al., "Systematic Field Study of NO_x Emission Control Methods for Utility Boilers," ESSO Research and Engineering Co., GRU.4GNOS.71, December 1971.

4-41. Hollinden, G. A., et al., "NO_x Control at TVA Coal-Fired Steam Plants," ASME Air Pollution Control Division, Proceedings of the Third National Symposium, April 24-25, 1973.

4-42. "Applicability of NO_x Combustion Modifications to Cyclone Boilers (Furnaces)," (Draft) Monsanto Research Corp., 1976.

4-43. "Standard Support Document and Environmental Impact Statement — Stationary Reciprocating Internal Combustion Engines," Prepared by Aerotherm Division of Acurex Corporation, Mountain View, California for U.S. Environmental Protection Agency, Contract 68-03-1318, Task No. 7, March 1976.

4-44. Hollinden, G. A., et al., "Evaluation of the Effects of Combustion Modifications in Controlling NO_x Emissions at TVA's Widow's Creek Steam Plant," EPRI SR-39, February 1976.

4-45. "Preliminary Test Results of NO_x Controls on Industrial Boilers — Appendix A," KVB Engineering.

4-46. McCann, C., et al., "Combustion Control of Pollutants from Multiburner Coal-Fired System," U.S. Bureau of Mines, EPA 650/2-74-038, NTIS-PB 233 037/AS, May 1974.

4-47. Breen, B. P., "Combustion in Large Boilers: Design and Operating Effects on Efficiency and Emissions," KVB, Inc. Paper presented at the 16th Symposium (International) on Combustion, Massachusetts Institute of Technology, Cambridge, Massachusetts, August 15-21, 1976.

4-48. Maloney, K. L., "Western Coal Use in Industrial Boilers," Western States Section/The Combustion Institute, April 19-20, 1976, Salt Lake City, Utah.

4-49. "Standard Support and Environmental Impact Statement for Standards of Performance: Lignite-Fired Steam Generators," (First Draft), EPA, March 1975.

4-50. Locklin, D. W., et al., "Design Trends and Operating Problems in Combustion Modification of Industrial Boilers," Battelle-Columbus Lab., EPA 650/2-74-032, NTIS-PB 235 712/AS, April 1974.

4-51. Hall, R. E., et al., "Study of Air Pollutant Emissions from Residential Heating Systems," EPA 650/2-74-003, NTIS-PB 229 697/AS, January 1974.

4-52. Cichanowicz, J. E., et al., "Pollutant Control Techniques for Package Boilers, Phase I Hardware Modifications and Alternate Fuels," (Draft Report) Ultrasystems and Foster Wheeler, November 1976.

4-53. Cato, G. A., et al., "Field Testing: Application of Combustion Modification to Control Pollutant Emissions from Industrial Boilers — Phase II," KVB Engineering, Environmental Protection Technology Series, EPA 600/2-76-086a, NTIS-PB 253 500/AS, April 1976.

4-54. Barrett, R. E., et al., "Field Investigation of Emissions from Combustion Equipment for Space Heating," Battelle-Columbus Laboratories, EPA-R2-73-084a, NTIS-PB 223 148, June 1973.

4-55. Combs, L. P., and A. S. Okuda, "Commercial Feasibility of an Optimum Distillate Oil Burner Head," Final Report, Rocketdyne Division, Rockwell International Corporation.

4-56. Combs, L. P., and A. S. Okuda, "Residential Oil Furnace System Optimization — Phase I," Rocketdyne Division, Rockwell International, EPA 600/2-76-038, NTIS-PB 250 878/AS, February 1976.

4-57. Combs, L. P., and A. S. Okuda, "Commercial Feasibility of an Optimum Residential Oil Burner Head," Rocketdyne Division, Rockwell International, EPA 600/2-76-256, NTIS-PB 259 912/AS, September 1976.

4-58. Combs, L. P., et al., "Integrated Low-Emissions Residential Furnace," Proceedings of the Stationary Source Combustion Symposium; Volume II — Fuels and Process Research and Development, EPA 600/2-76-152b, NTIS-PB 256 321/AS, June 1976.

4-59. Ketels, P. A., et al., "A Survey of Emissions Control and Combustion Equipment Data in Industrial Process Heating," Final Report by Institute of Gas Technology for EPA, IGT Project No. 8949, June 1976.

4-60. Shoffstall, D. R., "Burner Design Criteria for Control of NO_x from Natural Gas Combustion, Volume I," Institute of Gas Technology, EPA 600/2-76-098a, NTIS-PB 254 167/AS, April 1976.

4-61. Ando, J., et al., "NO_x Abatement for Stationary Sources in Japan," EPA 600/2-76-013b, NTIS-PB 250 586/AS, January 1976.

4-62. Hunter, S.C., et al., "Application of Combustion Technology for NO_x Emissions Reduction on Petroleum Process Heaters," presented at 83rd National Meeting AIChE, Houston, Texas, March 1977.

4-63. Copeland, J. O., "Standards Support and Environmental Impact Statement: An Investigation of the Best Systems of Emission Reduction for Nitrogen Oxides from Large Coal-Fired Steam Generators," (Draft) EPA, October 1976.

4-64. Thompson, R. E., et al., "Effectiveness of Gas Recirculation and Staged Combustion in Reducing NO_x on a 560 MW Coal-Fired Boiler," EPRI SR-39, February 1976.

4-65. Bagwell, F. A., et al., "Utility Boiler Operating Modes for Reduced Nitric Oxide Emissions," Journal of the Air Pollution Control Association, Vol. 21, pp. 702-708, 1971.

4-66. Barr, W. H., et al., "Retrofit of Large Utility Boilers for Nitric Oxide Emission Reduction — Experience and Status Report," paper presented at the 69th Annual AIChE Meeting, November 30, 1976.

4-67. Norton, D. M., et al., "Modifications to Ormond Beach Steam Generators for NO_x Compliance," paper presented at the ASME Winter Annual Meeting, November 30, 1975, Houston, Texas, ASME Paper No. 75-WA/PWR-9.

4-68. Heap, M. P., et al., "Reduction of NO Emissions from Package Boilers," Revised Draft Final Report by Ultra Systems, Inc., Irvine, California.

4-69. Durkee, K. R., et al., "An Investigation of the Best Systems of Emission Reduction for Stationary Gas Turbines — Standards Support and Environmental Impact Statement," (Draft) EPA, Research Triangle Park, N.C., July 1976.

4-70. Breen, B. P., "Control of the Nitric Oxide Emissions from Fossil Fueled Boilers," The Fourth Westinghouse International School for Environmental Management, July 15-18, 1973.

4-71. Bell, A. W., et al., "Combustion Control for Elimination of Nitric Oxide Emissions from Fossil Fuel Power Plants," 13th International Symposium on Combustion, University of Utah, August 23-29, 1970.

4-72. Bell, A. W., et al., "Nitric Oxide Reduction by Controlled Combustion Processes," KVB, Inc., Western States Section/Combustion Institute, April 20-21, 1970.

4-73. Jain, L. K., et al., "State of the Art for Controlling NO_x Emissions, Part I, Utility Boilers," Catalytic, Inc., EPA-R2-72-072a, NTIS-PB 213 297, September 1972.

4-74. Norton, D. M., et al., "Status of Oil-Fired NO_x Control Technology," EPRI-SR-39, February 1976.

4-75. Friedrich, J. L., et al., "Nitrogen Oxides Reduction," Foster Wheeler Energy Corp., EPRI SR-39, February 1976.

4-76. Lachapelle, D. G., "Staged Combustion Technology for Tangentially-Fired Utility Boilers Burning Western Coal," (Draft) February 1976.

4-77. Muzio, L. J., et al., "Package Boiler Flame Modifications for Reducing Nitric Oxide Emissions, Phase II of III," Ultrasystems, Inc., EPA-R2-73-292b, NTIS-PB 236 752, June 1974.

4-78. Seabrook, H. and B. P. Breen, "A Practical Approach to NO_x Reduction in Utility Boilers," Con Edison Co. of New York and KVB, presented at American Power Conference, April 18-20, 1972.

4-79. Shimizu, A. B., et al., "NO_x Combustion Control Methods and Costs for Stationary Sources Summary Study," EPA 600/2-75-046, NTIS-PB 246 750/AS, September 1975.

4-80. Cato, G. A., et al., "Field Testing: Application of Combustion Modification to Control Pollutant Emissions from Industrial Boilers — Phase I," KVB Engineering, EPA 650/2-74-078a, NTIS-PB 238 920/AS, October 1974.

4-81. Heap, M.P., et al., "Application of NO_x Control Techniques to Industrial Boilers," Ultrasystems, Inc., presented at the 69th Annual Meeting of the AIChE, Nov. 28-Dec. 2, 1976.

4-82. Fenimore, C. P., et al., "Formation and Measurements of Nitrogen Oxides in Gas Turbines," ASME 70-WA/GT-3, August 3, 1970.

4-83. Heap, M. P., et al., "Burner Design Principles for Minimum NO_x Emissions," EPA 650/2-73-021, NTIS-PB 224 210/AS, September 1973.

4-84. Heap, M. P., et al., "The Effect of Burner Parameters on Nitric Oxide Formation in Natural Gas and Pulverized Fuel Flames," IFRF, American Flame Research Committee, Sept. 6-7, 1972.

4-85. Pershing, D. W., et al., "Relationship of Burner Design to the Control of NO_x Emissions Through Combustion Modification," EPA 650/2-73-021, NTIS-PB 224 210/AS, Sept. 1973.

4-86. Shoffstall, D. R., "Burner Design Criteria for Control of Pollutant Emissions from Natural Gas Flames," Institute of Gas Technology, EPA 600/2-76-152b, NTIS-PB 256 321/AS, June 1976.

4-87. Koppang, R. R., "A Status Report on the Commercialization and Recent Development History of the TRW Low-NO_x Burner," TRW Energy Systems Group.

4-88. Tsuji, S., et al., "Control Technique for Nitric Oxide — Development of New Combustion Methods," IHI Engineering Review, Vol. 6, No. 2.

4-89. Ando, J., et al., "NO_x Abatement for Stationary Sources in Japan," August 1976 (Preliminary Draft).

4-90. Brackett, C. E., and J. A. Barsin, "The Dual Register Pulverized Coal Burner — A NO_x Control Device," EPRI SR-39, February 1976.

4-91. Vatsky, J., and R. P. Welden, "NO_x — A Progress Report," Foster Wheeler Corp., Heat Engineering, July-Sept., 1976, Vol. 48, No. 8.

4-92. Dickerson, R. A., and A. S. Okuda, "Design of an Optimum Distillate Oil Burner for Control of Pollutant Emissions," EPA 650/2-74-047, NTIS-PB 236 647/AS, June 1974.

4-93. Singh, P. P., et al., "Formation and Control of Oxides of Nitrogen Emissions from Gas Turbine Combustion Systems," ASME 72-GT-22, October 1972.

4-94. Roessler, et al., "Assessment of the Applicability of Automotive Emission Control Technology to Stationary Engines," Aerospace Corporation, EPA 650/2-74-051, NTIS-PB 237 115/AS, July 1974.

4-95. Spadaccini, L. J., and E. J. Szetela, "Approaches to the Prevaporized-Premixed Combustor Concept for Gas Turbines," ASME 75-GT-85.

4-96. Anderson, David, "Effects of Equivalence Ratio and Dwell Time on Exhaust Emissions from an Experimental Premixing Prevaporizing Burner," Lewis Research Center, ASME 75-GT-69.

4-97. Cornelius, W., and W. R. Wade, "The Formation and Control of Nitric Oxide in a Regenerative Gas Turbine Burner," General Motors Corp., SAE 700708.

4-98. Wade, W. R., et al., "Low Emissions Combustion for the Regenerative Gas Turbine," ASME 73-GT-11, January 1974.

4-99. White, D. J., and M. E. Ward, "Dry NO_x Control Techniques," EPRI SR-39, February 1976.

4-100. Mosier, S. A., et al., "Progress in Development of Low-NO_x Gas Turbine Combustors," United Technologies, for presentation at the 69th Annual AIChE Meeting, Nov. 28-Dec. 2, 1976.

4-101. Teixeira, D. P., "Overview of Water Injection for NO_x Control," EPRI SR-39, February 1976.

4-102. Armento, W. J., and W. L. Sage, "The Effect of Design and Operation Variables on NO_x Formation in Coal-Fired Furnaces," Alliance Research Center/B&W Pulverized Coal Combustion Seminar, June 19-20, 1973.

4-103. Lyon, R. K., "Method for the Reduction of the Concentration of NO in Combustion Effluents Using Ammonia," U.S. Patent No. 3,900,554, assigned to Exxon Research and Engineering Company, Linden, New Jersey, August 1975.

4-104. Lyon, R. K., and J. P. Longwell, "Selective, Non-Catalytic Reduction of NO_x by NH_3," Proceedings of the NO_x Control Technology Seminar, EPRI SR-39, February 1976.

4-105. Muzio, L. J., and T. K. Arand, "Homogeneous Gas Phase Decomposition of Oxides of Nitrogen," EPRI Report FP-253, August 1976.

4-106. Teixeira, D. P., "Status of Utility Application of Homogeneous NO_x Reduction," Proceedings of the NO_x Control Technology Seminar, EPRI SR-39, February 1976.

4-107. Bartok, W., et al., "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources," Final Report — Volume II, Esso Research and Engineering, Prepared for NAPCA, NTIS-PB 192 789, November 1969.

4-108. Blakeslee, C. E., and A. P. Selker, "Program for the Reduction of NO_x from Tangential Coal-Fired Boilers, Phase I," Environmental Protection Technology Series, EPA 650/2-73-005, NTIS-PB 226 547/AS, August 1973.

4-109. Lachapelle, D. G., et al., "Overview of the Environmental Protection Agency's NO_x Control Technology for Stationary Combustion Sources," presented at the 67th AIChE Annual Meeting, December 1974.

4-110. Kelley, D. V., data submitted at the EPRI NO_x Control Technology Seminar, San Francisco, by Pacific Gas and Electric Company, February 1976.

4-111. Personal communication — letter from the Los Angeles Department of Water and Power to Acurex Corporation, May 5, 1975.

4-112. "Power Costs, 1974 Report on Diesel and Gas Engines," The American Society of Mechanical Engineers (ASME), March 1974.

4-113. Personal communication, R. J. Lenney, Blueray Systems, Inc., Weston, Massachusetts, September 1975.

4-114. Satterfield, C. N., et al., "Catalytic Desulfurization and Denitrogenation," EPA 600/2-75-063, NTIS-PB 248 101/AS, October 1975.

4-115. Frost, C. M., et al., "Hydrodenitrification of Crude Shale Oil," Laramie Energy Research Center, LERC/RI-75/3, July 1975.

4-116. Jimeson, R. M., and L. W. Richardson, "Census of Oil Desulfurization to Achieve Environmental Goals," AIChE No. 148, Vol. 71.

4-117. Personal communication with Harry F. Mason of Chevron Research Company, Richmond, California, January 1977.

4-118. Guth, E. D., et al., "Method for Removing Sulfur and Nitrogen in Petroleum Oils," U.S. Patent No. 3,847,800, Nov. 12, 1974.

4-119. Personal communication with E. D. Guth — KVB Engineering, January 11, 1977.

4-120. Wright, C. H., "Sulfur and Nitrogen Balances in the Solvent Refined Coal Process," Pittsburg and Midway Coal Mining Company, EPA 650/2-75-011, NTIS-PB 243 893/AS, January 1975.

4-121. Meyers, R. A., "Desulfurize Coal Chemically," TRW Systems and Energy — Hydrocarbon Processing, June 1975.

4-122. Personal communication with Mr. Van Nuys of TRW Systems and Energy, Redondo Beach, CA., January 1977.

4-123. Stambaugh, E. P., et al., "Hydrothermal Coal Desulfurization with Combustion Results," EPA/RTP Contract 68-02-2119.

4-124. Stambaugh, E. P., "Battelle Develops Leaching Process to Desulfurize Coal," Coal Age, August 1975.

4-125. Shaw, H., "Reduction of Nitrogen Oxide Emissions From a Gas Turbine Combustor by Fuel Modifications," Journal of Engineering for Power, October 1973.

4-126. McCreath, C. G., "The Effect of Fuel Additives on the Exhaust Emissions From Diesel Engines," Combustion and Flame, Vol. 17, 1971 p. 359.

4-127. Altwicker, E. R., et al., "Pollutants From Fuel Oil Combustion and the Effects of Additives," Paper No. 71-14, 64th Annual APCA Meeting, Atlantic City, N.J., June 1971.

4-128. Martin, G. B., et al., "Effects of Fuel Additives on Air Pollutant Emissions From Distillate-Oil-Fired Furnaces," June 1971.

4-129. Pershing, D. W., et al., "Effectiveness of Selected Fuel Additives in Controlling Pollution Emissions From Residual-Oil-Fired Boilers," EPA 650/2-73-031, NTIS-PB 225 037/AS, October 1973.

4-130. Krause, H. H., et al., "Combustion Additives for Pollution Control — A State-of-the-Art Review," EPA 600/2-77-008a, January 1977.

4-131. Giammar, R. D., et al., "The Effect of Additives in Reducing Particulate Emissions From Residual Oil Combustion," Proceedings of the Stationary Source Combustion Symposium, EPA 600/2-76-152c, NTIS-PB 257 146/AS, Atlanta, June 1976.

4-132. Kukin, Ira, "Additives Can Clear Up Oil-Fixed Furnaces," Apollo Chemical Corp., Environmental Science and Technology, July 1973.

4-133. "National Energy Outlook," FEA/N-75/713, Federal Energy, Administration, February 1976.

4-134. Ctvrtnicek, T. E., et al., "Evaluation of Low-Sulfur Western Coal Characteristics, Utilization, and Combustion Experience," Monsanto Research Corp., EPA 650/2-75-046, NTIS-PB 243 911/AS, May 1975.

4-135. Martin, G. B., "Environmental Considerations in the Use of Alternate Clean Fuels in Stationary Combustion Processes."

4-136. Klepetch, R. D., and G. E. Vitti, "Gas Turbine Combustor Test Results and Combine Cycle Systems," Combustion, Vol. 45, No. 10, pp. 35-38, April 1974.

4-137. Frendberg, A., "Performance Characteristics of Exhibiting Utility Boilers When Fired With Low-Btu Gas," Proc. Conf. on Power Generation — Clean Fuels Today, EPRI, Monterey, California, April 8-10, 1974.

4-138. Joubert, J. I., and Daniel Bienstock, "Properties of Industrial Fuel Gases Manufactured From Coal Using Commercially Proven Technology," presented at the Symposium on Environment and Energy Conservation, Denver, Colorado, November 1975.

4-139. Shoffstall, D., "Preliminary Combustion Tests of Nine Drums of Stabilized Coal-Oil Emulsion," Systems Research Laboratories, Dayton, Ohio, Final Report 3205-43, March 1976.

4-140. Proceedings of the "Coal-Oil Mixture Combustion Technology Exchange Workshop," sponsored by ERDA, Report No. CONF-761019, Washington, D.C., October 29, 1976.

4-141. Martin, G. Blair, "Evaluation of NO_x Emission Characteristics of Alcohol Fuels in Stationary Combustion Systems," presented at Joint Meeting, Western and Central States Sections, The Combustion Institute, April 21 and 22, 1975, San Antonio, Texas.

4-142. Hall, R. E., "The Effect of Water/Residual Oil Emulsions on Air Pollutant Emissions and Efficiency of Commercial Boilers," ASME 75-WA/APC-1, July 14, 1975.

4-143. Hall, R. E., "The Effect of Water/Distillate Oil Emulsions on Pollutants and Efficiency of Residential and Commercial Heating Systems," APCA Paper No. 75-09.4, June 1975.

4-144. Pfefferle, W. C., et al., "CATATHERMAL Combustion: A New Process for Low-Emissions Fuel Conversion," presented at the 1975 ASME Winter Annual Meeting, Houston, Texas, ASME Paper No. 75-WA/FU-1.

4-145. Kesselring, J. P., et al., "Catalytic Oxidation of Fuels for NO_x Control from Area Sources," EPA Report, EPA 600/2-76-037, NTIS-PB 252 195/AS, February 1976.

4-146. DeCorso, S. M., et al., "Catalysts for Gas Turbine Combustors — Experimental Test Results," paper presented at the ASME Gas Turbine Conference and Products Show, New Orleans, March 1976, ASME Paper No. 76-GT-4.

4-147. LaNauze, R. D., "Fluidized Combustion," *Energy World Number 22*, December 1975.

4-148. "Design and Construction of a Fluidized-Bed Coal Combustion Sampling and Analytical Test Rig," Acurex/Aerotherm Proposal 2167-75-A, October 1975.

4-149. "Proceedings of the 4th International Conference on Fluidized Bed Combustion," McLean, Virginia, December 1975.

4-150. Fennelly, P. F., "Emission Estimates of NO_x and Organic Compounds from Fluidized Bed Combustion," presented at the International Conference on Photochemical Oxidant and Its Control, Raleigh, North Carolina, September 12-17, 1976.

4-151. Gerstin, R. A., "A Technical and Economic Overview of the Benefits of Repowering," paper presented at the Gas Turbine Conference and Products Show, Houston, Texas, March 2-6, 1975, ASME Paper No. 75-GT-16.

4-152. Ahuja, A., "Repowering Pays Off for Utility and Industrial Plants," *Power Engineering*, pp. 50-54, July 1976.

4-153. Robson, F. L. and A. J. Giramonti, "The Use of Combined-Cycle Power Systems in Nonpolluting Central Stations," JAPCA, Vol. 22, pp. 177-180, (1972).

4-154. Amos, D. J., et al., "Energy Conversion Alternatives Study (ECAS), Westinghouse Phase I Final Report, Volume V — Combined Gas Steam Turbine Cycles," NASA CR-134941, Volume V, 1976.

4-155. Stambler, I., "Field Test 5 MW Combined Cycle Package Set for 1978," *Gas Turbine World*, March 1976, pp. 10-13.

4-156. Papamarcos, J., "Combined Cycles and Refined Coal," Power Engineering, December 1976, pp. 34-42.

4-157. Kydd, P. H., "An Ultra High Temperature Turbine for Maximum Performance and Fuels Flexibility," paper presented at the Gas Turbine Conference and Products Show, Houston, Texas, March 2-6, 1975, ASME Paper No. 75-GT-81.

4-158. Force, E. L., and R. J. Ayen, "Catalytic Reduction of 50 to 5000 ppm Nitric Oxide by Carbon Monoxide," AIChE Symposium Series No. 126, Volume 68, 1972.

4-159. Koutsoukas, E. P., et al., "Assessment of Catalysts for Control of NO_x from Stationary Power Plants, Phase 1, Volume 1 Final Report," EPA 650/2-75-001a, NTIS-PB 239 745/AS, January 1975.

4-160. Ando, J. and H. Tohata, "NO_x Abatement Technology in Japan," EPA-R2-73-284, NTIS-PB 222 335, June 1973.

4-161. "Dry Scrubbing of Utility Emissions," Environmental Science and Technology, Volume 9, No. 8.

4-162. Habib, Y., and W. F. Bischoff, "Dry System for Flue Gas Cleanup," Oil and Gas Journal, February 24, 1975.

4-163. Pohlenz, J. P., "The Shell Flue Gas Desulfurization Process," presented at the EPA Flue Gas Desulfurization Symposium, Atlanta, November 1974.

4-164. Ploeg, J. E., et al., "How Shell's Flue Gas Desulfurization Unit has Worked in Japan," Petroleum International, Volume 14, No. 7, pp. 50-58, July 1974.

4-165. Stern, R., "The EPA Development Program for NO_x Flue Gas Treatment," in Proceedings of the National Conference on Health, Environmental Effects, and Control Technology of Energy Use, EPA Report 600/7-76-002, NTIS-PB 256 845/AS, February 1976.

4-166. Rosenberg, H. S., "Molecular Sieve NO_x Control Process in Nitric Acid Plants," EPA Report EPA 600/2-76-015, NTIS-PB 250 555/AS, January 1976.

SECTION 5

MULTIMEDIA EMISSION INVENTORY OF NO_x SOURCES

This section presents an inventory of multimedia emissions from the stationary fuel combustion NO_x sources and fuels identified in Section 2. Additionally the inventory for NO_x emissions is extended to include all other sources of NO_x (mobile, noncombustion, fugitive) in order to compare the contribution from stationary combustion sources. The NO_x inventory accounts for the degree of control applied to new and existing utility boilers. Multimedia pollutants inventoried include the primary criteria pollutants (NO_x, SO_x, CO, HC, particulates), sulfates, polycyclic organic material (POM), trace metals, and liquid or solid effluent streams. Results for sulfates, polycyclic organic matter, trace metals, and liquid and solid effluent streams are given in Appendix A. Insufficient data exist to quantify emissions for the other potential pollutants discussed in Section 3.

This inventory will serve as the base for assessing potential pollution problems in the absence of NO_x controls and for weighing the incremental emission input due to the use of NO_x controls. The inventory will also serve as the reference for the subsequent projections to the year 2000 in fuel and equipment use and stationary source emissions. Data gaps identified in the emission factor compilation highlight areas where further testing is needed in the NO_x E/A or other programs.

The emission inventory was generated through the following sequence:

- Compile fuel consumption data for the categories of combustion sources specified in Section 2 (Section 5.1)
  - Subdivide fuel consumption based on fuel-bound pollutant precursor composition
- Compile multimedia emission data (Section 5.2)
  - Base fuel-dependent pollutant emission factors on trace composition of fuels
  - Base combustion-dependent pollutant emission factors on unit fuel consumption for specific equipment designs
- Survey the degree to which NO_x, SO_x, particulates are controlled (Section 5.3)

- Produce emissions inventory (Section 5.4)
- Rank sources according to emission rates; compare to results of previous inventories (Section 5.5)

5.1 FUELS: PROPERTIES AND CONSUMPTION

This section characterizes fuel composition and consumption required in the emission inventory for stationary combustion sources of NO_x. U.S. energy use in 1974 totaled about 77 x 10^{15} kJ (72 x 10^{15} Btu) (Reference 5-1), of which 94 percent was supplied by the fossil fuels — coal, petroleum, and natural gas. Approximately 57 percent of the total energy was consumed by stationary source equipment. Fossil fuels furnished 92 percent of the energy for these stationary sources, with the remainder supplied by nuclear, hydroelectric, and other miscellaneous sources such as waste fuels, wood, geothermal, etc. Of the total amount of fossil fuels burned in stationary sources, coal and natural gas contributed 26 and 44 percent, respectively, and petroleum 30 percent. Unlike petroleum, which is also a major source of energy for transportation, coal and natural gas are consumed primarily in stationary applications.

The following discussion will focus exclusively on fossil fuels since they account for essentially all the energy consumed by stationary sources on a national basis. Section 5.1.1 briefly discusses each of the three major fossil fuels and their derivatives. Section 5.1.2 gives a detailed summary of the amount of each fuel consumed by the major stationary source equipment sectors and by individual equipment types within each sector. In the case of industrial process heating sources, figures on annual production rather than fuel consumption are given. No estimates of either fuel consumption or production are given for mobile, incineration, and fugitive NO_x emission sources.

5.1.1 Fuel Properties

Because of the variation in origin and processing, fossil fuels show large variations in both chemical and physical properties. Since data on fuels will be used in this report to estimate multimedia effluents produced by combustion, it is necessary to represent the majority of fuel variables by one or more sets of average values. There were many reasons for taking this approach:

- There are no comprehensive data which relate fuel consumption with exact fuel properties or origin
- Emission factors, with few exceptions, are in terms of average fuel properties (see Section 5.2)

- No comprehensive data exist on the various fuel cleaning practices such as blending, washing, desulfurization, demetallization, etc., employed by suppliers or users of fuel
- The nonhomogeneous nature of any fuel sample, especially coal and oil, makes exact characterization impossible (Reference 5-2)

An exception to the rule is the sulfur content of electrical utility fuels which is rigorously monitored. It is possible therefore to define the sulfur content of several residual oil and coal fuels fairly accurately. Sulfur contents of the following fuels represent the fossil fuels consumed by stationary sources:

- Petroleum products
    - Residual fuel oil
        - High S — 2.0 percent
        - Medium S — 1.0 percent
        - Low S — 0.5 percent
    - Distillate fuel oil, 0.25 percent S
    - Gasoline, 0.0 percent S
- Coal
    - Bituminous and subbituminous
        - High S — 2.8 percent (Interior Province origin)
        - Medium S — 2.2 percent (Eastern Province origin)
        - Low S — 1.6 percent (Western Province origin)
    - North Dakota lignite, 0.4 percent S
    - Pennsylvania anthracite, 0.6 percent S
- Natural gas, <0.1 percent S

The medium sulfur levels of coal and residual oil correspond to the average sulfur concentration of fuels used in U.S. utilities in 1974 (Reference 5-3). Data on sulfur composition of the fuels were available for the utility boiler sector, but there were relatively little data available for the other sectors. When specific sulfur content for fuel consumption data was not available, medium sulfur concentration levels were used where applicable.

The nitrogen content of fuels was treated differently than the sulfur content. This is because, in contrast to SO_x emissions, NO_x emissions are highly dependent on equipment design and combustion conditions and are a composite of thermal NO_x and fuel nitrogen conversion. Therefore, variations in NO_x emissions due to fuel nitrogen content are treated by specifying emission factors for each equipment/fuel combination, e.g., tangential utility boilers firing bituminous coal, watertube package boilers firing residual oil, rather than directly relating emissions to fuel nitrogen content.

Liquid and solid fuels invariably contain some trace element contamination; this is especially important in the combustion of residual fuel oil and coal where concentration levels are greatest and large amounts are burned each year. Natural gas, distillate oil, and gasoline are assumed to contain no trace elements. This assumption will have an insignificant impact on total trace element emissions from stationary sources.

It is practical to use representative concentration levels for coal since the trace element content of individual coal samples is highly variable. Trace element concentrations typically vary within a single coal-producing region, and even within a single seam (Reference 5-4). More refined specifications of the trace element content of various coals are unwarranted at this time because the available data on trace element emission factors have proven to be of poor quality. One study, in fact, suggests that trace element emissions from fossil fuels are so variable that they must be determined on a plant-to-plant basis (Reference 5-5).

Trace elements in residual fuel oils are even more variable than those in coal. This is compounded by the lack of specific data on the origin, refinery practices, and blending techniques of the residual oil used at the burner. Demetallization, desulfurization, and blending of various grades of oil vary from refinery to refinery. Supply and demand strongly influence the movement of petroleum. Further, supply and demand requirements are difficult to predict so that assumptions on refinery origins are bound to change. As a result, only a single average set of trace element concentrations will be used for residual fuel oil. This will be further justified when emission factors for these elements are presented in Section 5.2.

Table 5-1 gives the trace element concentrations and summarizes other important properties of each of the major types of fossil fuels. These properties will be used throughout the remainder of this section.

5.1.2 Fuel Consumption

This section presents estimates of stationary source fuel consumption (or of annual production in the case of process heating sources) needed to estimate multimedia effluents. The discussion includes the sources for these estimates and comments as to the reliability of the estimates. Fuel

TABLE 5-1. PROPERTIES AND TRACE ELEMENTS OF REPRESENTATIVE FOSSIL FUELS (References 5-6, 5-7, 5-8, 5-9)

T-193a

	Anthracite Coal	Subbituminous and Bituminous			Lignite Coal	Residual Fuel Oil			Distillate Oil	Gasoline	Natural Gas
		High S	Medium S	Low S		High S	Medium S	Low S			
Ash %	11.9	9.	9.2	8.7	12.8	0	0	0	0	0	0
Sulfur %	0.6	2.8	2.2	1.6	0.4	2.0	1.0	0.5	0.25	0	0
Heating Value	30,238 kJ/kg	27,912	27,912	23,260	18,608	39,021 kJ/ℓ			39,021 kJ/ℓ	34,840 kJ/ℓ	37,259 kJ/m³
Al (ppm)	--	12,240		10,200	8,160	753			0	0	0
Sb	0.1	1.3		1.1	0.9	0.2					
As	9.3	15		13	10	0.2					
Ba	54	36		30	24	39					
Be	2.8	1.7		1.5	1.2	--					
Bi	0.1	1.		0.8	0.7	--					
B	1.0	114		95	76	3.0					
Cd	0.1	2.9		2.4	2.0	2.0					
Co	84	9.1		7.6	6.1	30.					
Cr	112	14.		12.	10.	30.					
Cu	70	40.		33	26	25.					
Pb	8.3	14		12	9.2	19					
Mn	169	53		45	36	25					
Hg	0.3	0.2		0.2	0.1	0.1					
Mo	9.3	8.0		6.7	5.3	2.5					
Ni	47	22		19	15	1,208					
P	--	63		53	42	--					
Se	0.2	2.0		1.7	1.3	10					
V	12	33		28	22	1,803					
Zn	31	312		260	208	40					
Zr	45	72		60	48	19					

consumption data were compiled for the year 1974, the most recent period for which comprehensive data were available. By way of summary, the totals for coal, petroleum, and gas combustion are given in Table 5-2. It is important to note that these totals do not reflect the total amount of energy consumed by stationary sources because the process industries have been excluded along with electrical inputs originating from nonfossil fuel sources.

5.1.2.1 Utility and Large Industrial Boilers

Fuel consumption estimates for utility boilers are accurate and comprehensive in terms of both (1) total amount consumed and (2) the fraction due to each type of fuel. This is extremely valuable information, since relatively extensive emission factor data are also available for this sector. Table 5-3 gives a detailed summary of the fuel consumed by those utility boiler equipment types determined to be of significance in Section 2. The following sources of data were used to compile this summary:

- FPC — fuel consumption by type of fuel and sulfur content (References 5-3, 5-10)
- GCA — analysis of FPC-67 tapes to provide data on total number of boilers and equipment and fuel breakdown (Reference 5-6)
- Monsanto — analysis of cyclone boiler population and fuel consumption (Reference 5-11)
- OAQPS — analysis of lignite-fired steam generators (Reference 5-12)
- A. D. Little — analysis of the electric utilities and equipment manufacturers (Reference 5-13)
- Battelle — analysis of boiler population and fuels for nonutility application (Reference 5-14)
- Bureau of Mines — data on domestic coal production and end use by state; data on petroleum products (Reference 5-15)
- "Power" Magazine — miscellaneous information on various equipment and fuel trends (Reference 5-16)

To simplify these estimates, several basic assumptions were made:

- Distillate oil and kerosene were combined with the residual fuel oil category. The reason for this is that distillate oil accounted for only about 5 percent of utility steam plant total oil consumption (References 5-14 and 5-17)
- Coke, coke breeze, refuse, process gas, wood, bagasse, black liquor, sewer sludge, etc., have negligible application in utility boilers

TABLE 5-2. 1974 STATIONARY SOURCE FUEL CONSUMPTION

	Coal 10^{15} kJ/yr	Oil 10^{15} kJ/yr	Gas 10^{15} kJ/yr	Total 10^{15} kJ/yr
Utility Boilers	10.833	3.483	4.906	19.222
Packaged Boilers[b]	3.449	5.801	6.323[a]	15.573
Warm Air Furnaces and Miscellaneous Combustion	—	2.132	4.542	6.674
Gas Turbines	—	0.844	0.681	1.525
Reciprocating IC Engines	—	0.327[c]	0.913[d]	1.240
Total	14.282	12.587	17.365	44.234

[a] Includes process gas

[b] This sector includes steam and hot water units

[c] Includes gasoline and oil portion of dual fuel

[d] Includes natural gas portion of dual fuel

TABLE 5-3. UTILITY BOILER FUEL CONSUMPTION (kJ X 10^{-15})

Utility Boilers	Medium Sulfur Bituminous and Subbituminous	High Sulfur Bituminous and Subbituminous	Low Sulfur Bituminous and Subbituminous	Lignite	Anthracite	Total Coal	High S Residual and Crude	Medium S Residual and Crude	Low S Residual and Crude	Total Residual and Crude	Distillate	Total Oil	Natural Gas	Total All Fuels
Tangential	2.624	1.584	0.869	0.053	—	5.130	0.196	0.492	0.636	1.324	0.036	1.360	1.134	7.624
Single Wall-Fired	1.513	0.914	0.501	0.011	—	2.938	0.196	0.493	0.637	1.326	0.169	1.495	2.453	6.886
Opposed Wall and Turbofurnace	0.423	0.255	0.140	0.021	—	0.839	0.079	0.199	0.258	0.537	0.015	0.552	1.258	2.649
Cyclone	0.158	1.292	—	0.137	—	1.588	0.012	0.028	0.037	0.076	—	0.076	0.061	1.725
Vertical and Stoker	0.110	0.110	—	0.009	0.109	0.338	—	—	—	—	—	—	—	0.338

T-146

Coal accounted for 56 percent of the fuel consumed by utility boilers, natural gas 26 percent, and oil 18 percent. Coal consumption in utility boilers is about 76 percent of the total energy supplied by coal to all stationary sources. For gas and oil the amounts burned in utility boilers totaled only 30 and 28 percent, respectively, of the total of these fuels consumed by stationary sources.

5.1.2.2 Packaged Boilers

Data on the fuel consumption of packaged boilers are not as reliable as data for utility boilers. This is due in part to the large number of installed units, the diversity of design, the wide variety of applications, and the fuel flexibility of many of these units. Table 5-4 lists the fuel consumption estimates for the boiler designs in this sector which consume significant amounts of fuel. These estimates were derived from a number of sources:

- Battelle — analysis of the national boiler population by capacity and fuel (Reference 5-14)
- Battelle — analysis of equipment design distribution (Reference 5-18)
- U.S. Department of Commerce — data on boiler sales 1968 to 1974 (Reference 5-19)
- TRC — historical trends in package boiler fuels (Reference 5-20)

The following assumptions were used to estimate fuel consumption for packaged boilers:

- All boilers greater than 29 MW in capacity are watertube designs and are single-wall fired
- Pulverized coal is not fired in units of capacity less than 29 MW
- All coal burned for residential and commercial heating is used in steam and hot water units

In 1974, energy supplied to packaged boilers was 34 percent of the total fossil fuel consumed by stationary sources for energy conversion. Of this total consumption, coal supplied 24 percent of the energy, oil 42 percent, and gas 34 percent. In comparison to the utility boiler sector, it is clear that easily transported and distributed fuels are important for packaged boilers. Whereas for utility boilers coal is the most heavily used fuel, in packaged boilers coal is used almost exclusively in the larger watertube and older stoker units. Coal is seldom used in the new firetube or the smaller watertube boilers.

T-147a

Table 5-4. 1974 PACKAGED BOILER FUEL CONSUMPTION (kJ x 10^{-15})

Packaged Boilers	Anthracite	Bituminous or Lignite	Total Coal	Residual Oil	Distillate Oil	Total Oil	Natural Gas	Process Gas	Total Fuel
Watertube Boiler Wall firing >29 MW	—	0.510	0.510	0.637	0.085	0.723	0.928	0.130	2.290
Watertube Boiler Stoker >29 MW	—	0.466	0.466	—	—	—	—	—	0.466
Single Burner Watertube <29 MW	—	0.317	0.317	0.595	0.103	0.698	1.690	0.130	2.835
Single Burner Scotch Firetube <29 MW	—	—	—	0.945	0.446	1.391	0.972	0.019	2.382
Single Burner HRT Firetube <29 MW	—	—	—	0.370	0.263	0.633	0.535	—	1.168
Single Burner Firebox Firetube	—	—	—	0.609	0.403	1.012	0.899	0.019	1.930
Single Burner Cast Iron Boilers	—	—	—	0.195	0.181	0.377	0.264	—	0.641
Stoker Watertubes <29 MW	0.021	1.533	1.554	—	—	—	—	—	1.554
Stoker Firetubes <29 MW	0.042	0.556	0.598	—	—	—	—	—	0.598
Steam or Hot Water Units (Residential Only)	0.014	0.011	0.025	0.069	0.880	0.949	0.737	—	1.711

5.1.2.3 Warm Air Furnaces and Other Commercial and Residential Combustion

Here again, exact fuel consumption is difficult to estimate because of the extremely large number of units in the field and the large variety of available designs. Fuel consumption estimates for commercial and residential as well as various cooking appliances, clothes dryers, refrigeration units, etc. listed as "other" are presented in Table 5-5. The major source for these estimates was the 1970 U.S. Census (Reference 5-21).

The basic assumptions used in making these estimates were:

- The amount of wood, refuse, and other nonfossil fuels burned in warm air furnaces is minimal
- Units fueled by tank, bottled or liquefied petroleum gas are not a large portion of the total units; since these units are generally rurally located, they were combined with natural gas-fired units
- Coal is not fired in warm air furnaces, but when used in residential or commercial heating applications, it is burned in steam or hot water units

Total warm air furnace fuel consumption in 1974 represented about 15 percent of the total used in stationary sources for energy conversion. It is important to note that the amount of natural gas used in this sector is approximately equivalent to the amount used by utility and packaged boilers, whereas oil products are used considerably less.

5.1.2.4 Gas Turbines

1974 estimates of fuel consumption for gas turbines are considered to be of high quality because of the relatively small number of major applications and manufacturers of these units and the regulation of utility application. Table 5-6 gives the fuel consumption estimates for the important gas turbine capacity ranges defined in Section 2. These estimates are derived from a number of sources:

- GT-Standards Support Document — installation and generation for all applications and capacity ranges except utility (Reference 5-22)
- FPC — installation, generation, and fuel consumption for all utility applications (References 5-10 and 5-23)
- Sawyer's GT Catalog — miscellaneous information on utility and pipeline applications (Reference 5-24)
- GT International — data on gas turbine electric utility installations (Reference 5-25)

TABLE 5-5. 1974 WARM AIR FURNACE AND OTHER COMMERCIAL/RESIDENTIAL COMBUSTION ($kJ \times 10^{-15}$)

Warm Air Furnaces	Distillate Oil	Natural Gas[a]	Total Fuel
Warm Air Central Furnaces	1.405	3.091	4.497
Warm Air Room Heaters	0.727	1.451	2.178
Miscellaneous Commercial/Residential Combustion	—	1.0	1.0

[a] Includes bottled, tank or LPG

TABLE 5-6. 1974 GAS TURBINE FUEL CONSUMPTION ($kJ \times 10^{-15}$)

Gas Turbines	Natural Gas	Oil[a]	Total
Gas Turbines >15 MW	0.212	0.264	0.476
Gas Turbines 4 MW to 15 MW	0.468	0.579	1.047
Gas Turbines <4 MW	0.001	0.001	0.002

[a] Includes distillate, diesel, residual oils

These estimates were based on the following assumptions:

- Typical specific heat rates for the three capacity ranges were 10.9 MJ/kW-hr (10,300 Btu/kW-hr), 13.9 MJ/kW-hr (13,200 Btu/kW-hr) and 16.4 MJ/kW-hr (15,500 Btu/kW-hr) for large, medium, and small capacity turbines, respectively
- Specific fuel consumption does not vary with load, which means total fuel consumption can be determined directly from specific fuel consumption and generation totals
- The amount of alternate fuels such as gasified or liquefied coals, shale oil, process gas, pulverized coal, refuse, etc. burned in turbines is negligible
- Supplementary fired combined-cycle turbine fuel consumption was minimal in 1974

The total energy consumed by gas turbines was about 3.5 percent of the total stationary source fuel consumption in 1974. As Table 5-6 shows, medium-capacity units consumed more total fuel than the large units. The bulk of the fuel consumption for these medium-capacity turbines was either in the oil and gas industry, where units operate almost constantly, or in private sector electricity generation, where units operate about three-quarters of the time.

5.1.2.5 Reciprocating IC Engines

This sector is composed of an extremely wide range of designs, applications and manufacturers. A recent study (Reference 5-26), however, has extensively characterized reciprocating IC engines in terms of installed capacity and annual generation by fuel, and data from this study have been used extensively for this sector. For consistency with other sections of this report, data from Reference 5-10 have been used for installed capacity, annual generation, and fuel consumption of IC engines used by electrical utilities. Table 5-7 gives fuel consumption figures for the significant types of equipment for this sector as determined in Section 2.

The following assumptions were used in arriving at these estimates:

- Specific fuel consumption averaged 9.9 MJ/kW-hr (7,000 Btu/hp-hr), 11.3 MJ/kW-hr (8,000 Btu/hp-hr), and 11.3 MJ/kW-hr for large, medium, and small capacity ranges respectively
- Specific fuel consumption does not vary with load, so that overall fuel consumption can be determined from specific fuel consumption and generation totals
- No gasoline is burned in large or medium capacity equipment
- No natural gas is burned in small capacity equipment

TABLE 5-7. 1974 RECIPROCATING IC ENGINE FUEL CONSUMPTION (kJ x 10^{-15})

Reciprocating IC Engines	Natural Gas	Distillate Oil (Diesel)	Gasoline	Dual (Oil + Gas)	Total Fuel
Compression Ignition >75 kW/cyl	—	0.054	—	0.058 Gas 0.012 Oil	0.123
Spark Ignition >75 kW/cyl	0.813	—	—	—	0.813
CI 75 kW to 75 kW/cyl >1000 RPM	—	0.129	—	—	0.129
SI 75 kW to 75 kW/cyl >1000 RPM	0.043	—	0.084	—	0.127
CI <75 kW	—	—	—	—	—
SI <75 kW	—	—	0.049	—	0.049

The total energy consumed by this sector is about 3 percent of the total stationary source energy conversion fuel consumption. Much more natural gas is used than oil, predominantly in the large-bore units. The major user of natural-gas-fired, large-bore engines is the oil and gas industry, where units operate essentially full-time.

5.1.2.6 Industrial Process Heating

For the industrial process heating equipment, production totals for various processes within the sector were used instead of fuel consumption totals. One reason for this approach is that emission factors for industrial process heating are usually presented in terms of production totals. Also, production figures are far more reliable than energy consumption statistics for the heating operations in most industries.

Table 5-8a gives production data for the major process heating industries. Table 5-8b presents refinery process heating fuel consumption for 1974. Because the statistics kept by industry associations are fairly complete, and there are a high number of reliable sources for this information, these data are considered to be of high quality. The primary sources for these statistics were:

- Walden — data on the iron and steel industry (Reference 5-27)
- Bureau of Mines — data on the iron and steel industry, cement industry, brick and ceramic industry (Reference 5-15)
- IGT — data on cement kilns, glass manufacture, petroleum refineries, cement industry (Reference 5-28)
- TRC — data on brick and ceramic kilns (Reference 5-20)
- Lockheed — data on refinery flaring (Reference 5-29)
- KVB — data on refinery process heaters (Reference 5-30)

5.2 EMISSION FACTORS

This section presents uncontrolled emission factors for the significant stationary sources of NO_x identified in Section 2 of this report. Emission factors were compiled for the following fuels: lignite, bituminous, and anthracite coal; distillate and residual oil, and natural gas. Since data from process gas utilization are inadequate, emission factors have not been included for this fuel. Whenever possible, emission factors will be expressed in terms of fuel inputs, i.e., nanograms NO_2 per Joule heat input. If emissions are less dependent on fuel consumption — as in the chemical process industries — they will be expressed as a function of product output.

TABLE 5-8a. 1974 INDUSTRIAL PROCESS HEATING PRODUCTION

Industrial Process Heating	Annual Production
Cement Kilns	7.696×10^7 Mg
Glass Melting Furnaces	1.542×10^7 Mg
Glass Annealing Lehrs	1.542×10^7 Mg
Coke Oven Underfire	5.701×10^7 Mg
Steel Sintering Machines	4.851×10^7 Mg
Open Hearth Furnaces	3.227×10^7 Mg
Brick and Ceramic Kilns	3.158×10^7 Mg
Catalytic Cracking	2.294×10^{11} ℓ feed
Refinery Flares	7773 Mg NO_x/yr[a]
Iron and Steel Flares	318 Mg NO_x/yr[a]

[a] NO_x estimates

TABLE 5-8b. 1974 REFINERY PROCESS HEATING FUEL CONSUMPTION (kJ x 10^{-15})

Heater Type	Natural Gas	Oil	Total
Natural Draft	1.119	0.2565	1.3755
Forced Draft	0.1282	0.0806	0.2088
Total	1.2472	0.3371	1.5843

Criteria pollutants, NO_x, SO_x, HC, CO, and total particulate, have been extensively tested and the quality of the resulting emission factors is generally high. Unfortunately, the quality of the measurements for less studied species — polycyclic organic material (POM), sulfates, and trace elements — varies widely. Tables of emission factors for criteria pollutants have been included in the text, while those for POMs, sulfates and trace metals and corresponding emissions are contained in Appendix A.

Figures for emission factors have been obtained from AP-42 (Reference 5-31) and its supplements, from a survey of existing literature, and from preliminary results of ongoing test programs. Whenever possible, AP-42 and its supplements have been used, since they typically reflect the most recent test results. In cases where emission factors are not available for specific design types from these sources, estimates of emission factors have been made from test results on similar equipment. In some instances, a range of emission factors is available and in these cases a representative average value has been assigned. Each of the following subsections includes a discussion of the sources for the data given on emission factors, along with the rationale for their selection and their relation to AP-42 emission factors. It should be emphasized that the following factors represent uncontrolled operating conditions without the use of pollution control devices, except where noted.

5.2.1 Utility and Large Industrial Boilers

Table 5-9 gives uncontrolled emission factors for the criteria pollutants from utility boilers. NO_x emission factors for these boilers were obtained from AP-42 supplements (References 5-32, 5-33). These values are in good agreement with measurements obtained from utility boiler field testing (References 5-34 through 5-41). Values for cyclone furnaces and lignite-fired boilers were obtained from more recent studies (References 5-11, 5-12).

Emission factors for SO_x, PART, HC, and CO were gathered from a search of the available literature for bituminous coal-fired, tangential, single-wall-fired or opposed-wall furnaces (References 5-34 through 5-41). Because there are very little available data for vertical-fired boilers, AP-42 emission factors (Reference 5-31) were used for this inventory. Emission factors for HC and CO from tangential, single- and opposed-wall, residual-oil-fired boilers were obtained from References 5-34 through 5-41. These numbers are considerably lower than AP-42 values. Particulate and SO_x emission factors from AP-42 used here are in excellent agreement with representative field testing (References 5-32, 5-33). AP-42 and its supplements were also used as a source of emission factors for distillate oil and natural gas, but these values have not been verified since boiler field tests of these fuels are not available.

TABLE 5-9. UTILITY BOILER CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

T-151a

Equipment Type	NO_x	SO_x[a]	Part[a,b]	CO	HC
Utility Boilers					
Tangential					
Anthracite	275	585S	261A	15.5	0.43
Bituminous and Subbituminous	275	602S	195A	11.2	0.86
Lignite	245	808S	175A	27.1	8.2
Residual Oil	153	482S	30.5S + 8.6 (30.5)	8.6	0.86
Distillate Oil	153	434S	6.0	15.5	6.0
Natural Gas	129	0.3	2.2 - 6.5 (4.3)	7.3	0.86
Single Wall-Fired					
Anthracite	322	585S	261A	15.5	0.43
Bituminous and Subbituminous	322	602S	186A	21.9	0.86
Lignite	353	808S	175A	27.1	8.2
Residual Oil	322	482S	30.5S + 8.6 (30.5)	13.3	0.86
Distillate Oil	322	434S	6.0	15.5	6.0
Natural Gas	301	0.3	2.2 - 6.5 (4.3)	11.6	0.86
Opposed Wall and Turbofurnace					
Anthracite	322	585S	261A	15.5	0.43
Bituminous and Subbituminous	322	602S	186A	8.6	0.86
Lignite	353	808S	175A	27.1	8.2
Residual Oil	322	482S	30.5S + 8.6 (30.5)	12.5	0.86
Distillate Oil	322	434S	6.0	15.5	6.0
Natural Gas	301	0.3	2.2 - 6.5 (4.3)	10.7	0.86
Cyclone					
Anthracite	559	585S	35.7A	15.5	6.45
Bituminous and Subbituminous	559	679S	35.7A	18.1	6.45
Lignite	374	808S	174.5A	27.1	8.17
Residual Oil	219	492S	30.5S + 8.6 (30.5)	15.5	6.02
Distillate Oil	219	6.0	6.0	15.5	6.02
Natural Gas	241	0.3	2.25 - 6.4 (4.3)	7.3	6.02
Vertical and Stoker					
Anthracite	269	585S	30.5A	92.0	3.01
Bituminous and Subbituminous	269	679S	233A	35.7	5.59
Lignite	269	808S	188A	53.7	8.17

[a] S represents the percent sulfur in the fuel, A represents the percent ash in the fuel

[b] Numbers in parentheses are average values

Polycyclic organic matter (POM) values for utility boilers come from References 5-41 and 5-42. Unfortunately, values for coal-fired power plants vary by two or three orders of magnitude depending upon equipment type. Consequently, a range of values has been given rather than a single specific value.

Sulfate emission factors for coal-fired utility boilers were determined from field testing (Reference 5-43).

Trace metallic emission factors for this sector come from References 5-5, 5-6, 5-9 and 5-44 through 5-48. There is fair agreement concerning the partitioning and enrichment properties of specific trace elements presented in these studies; however, agreement is not sufficient to warrant any more than average trace metal concentrations in the fuel. As a result, care must be used in applying these emission factors. It should be noted that they are presented here as estimates rather than as exact values.

5.2.2 Packaged Boilers

Packaged boilers were divided into two capacity groupings: boilers of capacity of 23 MW to 73 MW (100 to 250 MBtu/hr), and boilers of capacity of less than 29 MW of fuel. Table 5-10 presents uncontrolled emission factors for the criteria pollutants for these two classes of boilers. The emission factors given come from industrial boiler field tests (References 5-49 through 5-51) and AP-42 and its supplements (References 5-31 through 5-34).

The firing and emission characteristics of the large industrial boilers are similar to those of utility boilers. CO and HC emission factors for bituminous coal, oil, and gas obtained from the results of field tests (References 5-49 and 5-50) are considerably lower than those supplied by AP-42. NO_x, particulates, and SO_x emission factors for large packaged boilers came from both field tests (References 5-49, 5-50) and AP-42 and its supplements (References 5-31 through 5-33). There is excellent correspondence between these two data sources. Since there has been very little field testing of boilers firing anthracite coal, emission factors for this fuel are from AP-42.

Emission factors for the group of packaged boilers less than 29 MW capacity came largely from field tests of industrial and commercial boilers at baseline operating conditions (References 5-49 through 5-52). The data were averaged where baseline data were available for more than one unit of a specific design type. If test data were not available for a specific equipment/fuel combination, AP-42 numbers or test data from similar equipment were substituted.

In general, there is excellent correspondence between AP-42 supplements (References 5-32, 5-33) and field testing (References 5-49 through 5-52) for criteria pollutants from packaged boilers.

TABLE 5-10. PACKAGE BOILER CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

T-150b

Equipment Type	NO_x	SO_x[a]	Particulates[a]	CO	HC
Watertube-Wall Firing 29 MW to 73 MW					
Anthracite	322	585S	261A	0.6	0.43
Bituminous and Lignite	322	559S	186A	0.04	2.2
Residual Oil	322	408S	30.5S + 8.6	3.9	3.0
Distillate Oil	322	434S	7.74	—	3.0
Natural Gas	301	0.3	1.72	9.0	3.9
Process Gas	301	—	—	—	—
Watertube Stoker 29 to 73 MW					
Anthracite	269	584.7S	30.5A	92	3.0
Bituminous and Lignite	269	756.6S	233A	25	4.3
Watertube <29 MW					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	8.2	1.6	0.43
Natural Gas	98.9	3.4	3.4	8.6	1.7
Process Gas	98.9	—	—	—	—
Firetube Scotch					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	7.3	1.6	0.43
Natural Gas	98.9	0.3	2.6	8.6	1.7
Process Gas	98.9	—	—	—	—
Firetube/Firebox					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	7.3	1.6	0.43
Natural Gas	98.9	0.3	2.6	8.6	1.7
Process Gas	98.9	—	—	—	—
HRT Firetubes					
Residual Oil	184.5	482S	83	3.4	0.9
Distillate Oil	67.5	436S	3.9	1.7	0.4
Natural Gas	98.9	0.3	2.6	8.6	1.7
Cast Iron Boilers					
Residual Oil	184	482S	30.5S + 8.6	3.4	0.86
Distillate Oil	67.5	434S	3.7	1.6	0.43
Natural Gas	51.6	0.3	2.6	8.6	1.7
Watertube Stoker <29 MW					
Anthracite	179	585S	31A	92	3.0
Bituminous and Lignite	179	672S	232A	21	18

[a] S represents sulfur of fuel; A represents percent ash of the fuel

TABLE 5-10. Concluded

Equipment Type	NO_x	SO_x[a]	Particulates[a]	CO	HC
Firetube Stoker					
Anthracite	179	585S	31A	92	3.0
Bituminous and Lignite	179	672S	232A	21	18
Residential Steam Units					
Anthracite	179.3	585S	307	138	307
Bituminous and Lignite	179.3	679S	358.2	1612.5	358.2
Residual Oil	162	481S	83	15.48	3.01
Distillate Oil	55	434S	7.7	30.5	4.73
Natural Gas	34.4	0.26	4.3	8.6	3.4

T-150b

[a] S represents sulfur of fuel; A represents percent ash of the fuel

The only area of significant disagreement is the emission factors for small packaged oil-fired boilers, where values from field testing (References 5-49 through 5-52) are considerably lower than AP-42 supplement values (Reference 5-33). In general, small watertube, scotch firetube, firebox firetube, HRT firetube, and cast iron boilers fired by single burners have quite similar combustion characteristics and thus, similar emission factors.

POM emission factors for packaged boilers came from recent field testing (References 5-54 through 5-56), and from AP-33 (Reference 5-42). Again, there are several orders of magnitude between AP-33 values and the results of recent field tests. Because available data are scarce and available measurements vary widely, a range has been presented rather than specific values. In addition, it has been assumed that scotch firetubes, HRT firetubes and firebox firetubes have the same POM emission characteristics, and that shell boilers and cast iron boilers are also similar. A trend toward larger POM emissions from smaller units is clearly evident. Smaller units are usually less carefully regulated, which means less efficient firing and operation, resulting in poor combustion.

Field testing data for sulfate emissions and trace elements from packaged boilers are quite sparse. Some field testing has been performed (Reference 5-51), but little data have been quantified. It is assumed that trace element emission factors will be similar for large packaged and utility boilers since they often have similar operating characteristics to utility boilers. This assumption does not hold, however, for small packaged boilers. Care must be exercised in using trace element factors, since they may vary by two or more orders of magnitude depending on the fuel.

5.2.3 Warm Air Furnaces

Table 5-11 gives uncontrolled emission factors for the criteria pollutants from warm air furnaces. NO_x emission factors have been determined from the results of recent field tests (Reference 5-52) and from AP-42 supplements (Reference 5-33). Emission factors for the remaining criteria pollutants came from field testing (References 5-52, 5-53, 5-57), studies (References 5-58, 5-59), and AP-42 supplements (References 5-32, 5-33). In general, the agreement between these different sources of data is excellent. As a result, values from AP-42 supplements are felt to represent the emission characteristics of warm air furnaces accurately, and the majority of the emission factors given for warm air furnaces comes from these supplements.

Little testing has been done on POMs emitted from warm air furnaces. AP-33 (Reference 5-42) does report some POM emissions data. Since supporting data are lacking and most POM testing is inconsistent, these values, presented in Appendix A, are only an order of magnitude estimate of POM emissions.

TABLE 5-11. WARM AIR FURNACE AND MISCELLANEOUS COMMERCIAL AND RESIDENTIAL COMBUSTION CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Equipment Type	NO_x	SO_x[a]	Part	CO	HC
Warm Air Central Furnace					
Oil	61.0	434S	7.7	31	4.7
Natural Gas	34.4	0.358	2.2 - 6.5 (4.3)	12	3.4
Warm Air Room Heaters					
Oil	61.0	434S	7.7	31	4.7
Natural Gas	34.4	0.258	2.2 - 6.5 (4.3)	12	3.4
Miscellaneous Combustion[b]					
Natural Gas	34.4	0.258	2.2 - 6.5 (4.3)	12	3.4

[a] S represents percent sulfur in the fuel

[b] All miscellaneous combustion fuels (wood, LPG, etc.) combined with natural gas

[c] Numbers in parentheses denote average values

Sulfate emission factors from warm air furnaces were not available.

Trace element emission factors for warm air furnaces cannot be determined from the existing data. The only significant source would be the small number of coal-fired units. These are insignificant on a national scale but could present localized pollution problems.

5.2.4 Gas Turbines

Emission factors for gas turbines come from field studies (References 5-22, 5-60) and an AP-42 supplement (Reference 5-61). Table 5-12 presents uncontrolled emission factors for the criteria pollutants, primarily from the recent Gas Turbine Standard Support Document (Reference 5-22). Values from the AP-42 supplement in this section for non-NO_x criteria pollutants are in excellent agreement with values from field studies (References 5-60, 5-62).

Emission factors for POMs and sulfates from gas turbines cannot be determined at present due to the lack of representative field testing.

5.2.5 Reciprocating IC Engines

The range of equipment design combinations for reciprocating IC engines is so varied that it is impossible to determine emission factors for each equipment combination using the available data. Consequently, reciprocating IC engines have been categorized as either spark ignition or compression ignition engines in three capacity ranges. Table 5-13 presents uncontrolled emission factors for the criteria pollutants for these equipment types.

NO_x emission factors have been derived from values presented in a current IC engine study (Reference 5-26). Non-NO_x criteria pollutant emission factors come from recent AP-42 supplements (References 5-32, 5-33). These values correspond closely with the results of field tests (Reference 5-63).

Sufficient data are not available to quantify emission factors for POMs, sulfates, and trace elements from reciprocating IC engines. Trace element concentrations will vary by orders of magnitude depending on the fuel and the operating characteristics of the reciprocating engine measured. Because of this, determining specific emission factors to span this range of values is not possible.

5.2.6 Industrial Process Combustion

Direct process heat from fuel combustion has a wide range of industrial applications and is produced by many different types of equipment. In addition, process heat is generated in many

TABLE 5-12. GAS TURBINE CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

Equipment Types	NO_x	SO_x	PART	CO	HC
Gas Turbine >15 MW					
Natural Gas	195	2.2	6.0	49.0	8.6
Diesel oil	365	10.7	16.0	47.0	8.6
Gas Turbine 4 MW to 15 MW					
Natural Gas	194	2.2	6.0	49.4	8.2
Diesel oil	365	10.7	15.5	47.3	9.9
Gas Turbine <4 MW					
Natural Gas	194	2.2	6.0	49.4	8.2
Diesel oil	365	10.7	15.5	47.3	9.9

TABLE 5-13. RECIPROCATING IC ENGINE CRITERIA POLLUTANT EMISSION FACTORS (ng/J)

	NO_x	SO_x	PART	CO	HC
Comp Ignition >75 kW/cyl					
Dist Oil	1,741	95.9	103	313	115
Dual Fuel	1,023	—	—	—	—
Spark Ignition >75 kW/cyl					
Natural Gas	1,552	0.22	—	177	555
CI 75 kW to 75 kW/cyl >1,000 RPM					
Dist Oil	1,741	95.9	103	313	115
SI 75 kW to 75 kW/cyl >1,000 RPM					
Natural Gas	1,552	0.22	—	177	555
Gasoline	1,195	16.3	19.8	12,081	405
CI <75 kW 2-4 cyl					
Dist. Oil	1,677	95.9	95.9	313	115
SI 75 kW 2-4 cyl					
Gasoline	774	16.3	19.8	12,081	405

industries by a large number of small-scale processes which as a whole may have a significant impact, but which are individually hard to quantify. Nonetheless, there are several industries which constitute the major pollution sources, and these industries will be considered in this section. Uncontrolled emission factors for the criteria pollutants based on product output are presented in Table 5-14a. Refinery process heating emission factors are presented in Table 5-14b.

Cement and glass industries which use kilns, furnaces, and ovens to heat raw materials are a significant source of NO_x. Emission factors for NO_x from these processes come primarily from a recent study of these industries (Reference 5-28). Non-NO_x criteria pollutant emission factors have partially been determined from AP-42 values (Reference 5-31). Very few data are presently available for sulfates, POMs, and trace elements from cement kilns. Sulfate emission factors come from Reference 5-64, although the values presented are questionable.

The extensive use of ovens and furnaces in the iron and steel industry results in the production of major quantities of NO_x. Most of these emissions come from coke oven underfiring, steel sintering machines, and open hearth furnaces. Noncriteria pollutant emissions data from the iron and steel industry are not available. NO_x emission factors from the iron and steel industry have been determined from Reference 5-27. Other criteria pollutant factors come from References 5-20 and 5-27.

Other NO_x sources in the petroleum industry are refinery flares, fluid catalytic crackers and process heaters. NO_x emission factors for refinery flares and catalytic crackers were obtained from a recent study of process heating (Reference 5-28). NO_x emission factors from refinery process heaters were obtained from a recent study conducted by KVB (Reference 5-30). The values reported here are for both natural draft and forced draft refinery heaters firing gas and oil. The values are tentative pending completion of the KVB study. Emission factors for other criteria pollutants for refinery process heaters are based on values reported in AP-42. Emission factors for other criteria pollutants come from AP-42 (Reference 5-31) and from emission studies (References 5-20, 5-65). Noncriteria emission factors are not available.

The contact process used in the production of sulfuric acid requires burning of sulfur in a combustion chamber, which generates significant NO_x emissions. The emission factor for SO_x comes from Reference 5-20.

5.3 EFFECT OF EMISSION CONTROL REGULATIONS

The preceding section provided estimates of pollutant emission factors for the major stationary combustion sources without accounting for control devices which are currently being employed. Because of both state and local regulations, emissions of SO_x and particulates from the large point

TABLE 5-14a. INDUSTRIAL PROCESS COMBUSTION CRITERIA POLLUTANT EMISSION FACTORS (g/kg PRODUCT)

T-567a

	NO_x	SO_x	PART	CO	HC
Cement Kilns	1.30	5.09	122	NA	NA
Glass Melting Furnaces	3.68	2.12	1.0	NA	NA
Glass Annealing Lehrs	0.69	NA	NA	NA	NA
Coke Oven Underfire	0.07	2.84	37.7	NA	NA
Steel Sintering Lines	0.52	0.71	10.	22.	NA
Open Hearth Furnaces	0.62 oil 0.37 gas	0.70	6.	NA	NA
Brick & Ceramic Kilns	0.23	0.54	65.	0.1	0.04
Catalytic Cracking	0.20[a]	1.41[a]	0.69[a]	39.1[a]	0.63
Refinery Flares Iron & Steel Flares	[b]	NIL	NIL	NIL	0.43[c]

[a] g/l Feed

[b] Production is not quantifiable. Estimate of NO_x is made in fuel consumption section.

[c] g HC/l capacity

TABLE 5-14b. REFINERY PROCESS HEATING CRITERIA POLLUTANT EMISSION FACTORS (ng/J) (Reference 5-30)

Heater Type	Fuel	NO_x	SO_x	PART	CO	HC
Natural Draft	Gas	70.1	860S[b]	8.6	NIL[d]	12.9
	Oil[a]	154.8	627S[c]	78.4	NIL	13.07
Forced Draft	Gas	110.5	860S[b]	8.6	NIL	12.9
	Oil[a]	184.5	627S[c]	78.4	NIL	13.07

[a] Assumed fuel oil nitrogen content of 0.2 percent and a fuel nitrogen conversion to NO of 50 percent

[b] Refinery gas sulfur content (lb/100 ft^3)
(assumed 10 grain/100 ft^3 based on Federal EPA regulations)

[c] Fuel oil sulfur content (weight percent) (assumed 0.1 percent)

[d] Negligible emissions

sources have been extensively controlled. NO_x emissions have been less extensively regulated, however, so NO_x controls applied to existing equipment are less commonplace. This section describes the degree of control which now exists for particulates, SO_x, and NO_x and applies these controls to applicable equipment to more accurately represent present mass emission totals. The emission inventory presented in the following section gives particulate and SO_x emissions for the controlled state; only NO_x emissions are given for both uncontrolled and controlled uses for comparison.

5.3.1 Particulate Control

The most common types of particulate control equipment are centrifugal collectors and electrostatic precipitators. Coal- and oil-fired boilers contribute approximately 98 percent of utility boiler particulate emissions; hence the controls on these boilers are most important. Gas-fired boiler particulate emissions are insignificant and will not be considered further in this section. Representative values for the percent of particulate controls in the utility and industrial sector and the impacts of these controls on total particulate emissions are presented.

5.3.1.1 Utility Boilers

Information on the types of controls used on utility boilers of different sizes comes from NEDS and two recent particulate studies of emissions (References 5-6, 5-59, and 5-66). According to these studies, electrostatic precipitators and centrifugal collectors make up over 96 percent of the particulate controls installed on utility boilers. Twelve percent of pulverized coal-fired boilers have no collection devices. Table 5-15 displays the percent of particulate collected from utility boilers. Approximately 35 percent of oil-fired boilers are not controlled. Assuming representative efficiencies for control equipment types, it has been estimated that 75 percent of the particulate generated in residual oil-fired boilers is not collected. More importantly, 35 percent of the flyash formed in pulverized coal-fired boilers, 25 percent in cyclone boilers and 50 percent in stokers are also not collected.

5.3.1.2 Industrial Boilers

A recent source assessment document for industrial boilers (Reference 5-67) has been used to determine the distribution of controls for pulverized coal-fired boilers, stokers, and residual and distillate oil-fired boilers. Approximately 75 percent of small industrial stokers (<29 MW) and 30 percent of the larger boilers are not controlled. It is assumed that controls for small pulverized coal industrial boilers (<29 MW) are insignificant. As displayed in Table 5-15, about 50 percent of the particulate emissions from large coal-fired industrial boilers are collected. However, for

TABLE 5-15. AVERAGE PARTICULATE COLLECTION

Sector	Equipment/Fuel	Percent Collection
Utility Boilers	All/Pulv. Coal	65
	Cyclone/Coal	75
	Stoker/Coal	50
	All/Residual Oil	25
Package Boilers	29 to 73 MW	
	Wall-Fired/Pulv. Coal	50
	Stoker/Coal	50
	Wall-Fired/Residual Oil	5
	Wall-Fired/Distillate Oil	0
	<29 MW	
	Stoker/Coal	15
Industrial Process Combustion	Cement Kilns	88

smaller units, 95 percent of the particulates from residual oil-fired boilers and 15 percent of the particulates from small coal stokers are released to the atmosphere.

5.3.1.3 Industrial Processes

In the industrial sector, the cement industry is controlled extensively by the use of cyclones and electrostatic precipitators. Table 5-15 shows that approximately 12 percent of particulate emissions are not separated from the effluent stream by collection devices (Reference 5-68).

In Section 5.4 the emissions inventory will be displayed as a function of controlled particulates. Since the large majority of boilers do possess particulate controls, an uncontrolled inventory would not represent the current impact of controls implementation.

5.3.2 SO_x Control

To determine the extent of SO_x control on stationary combustion sources, the two commercially available means of SO_x control — flue gas desulfurization and low-sulfur fuel — were examined both for their extent of use and their effectiveness. Coal cleaning currently has seen insignificant use nationwide. Two recent surveys of flue gas desulfurization (References 5-69, 5-70) indicated that the total installed capacity of FGD equipment on utility-size boilers is about 5,000 MW. When this is compared to the total electrical utility boiler installed capacity of about 350,000 MW (Reference 5-10), the effect of FGD systems is clearly small.

The primary means of meeting local SO_x control regulations is through the use of low-sulfur fuel either totally or in blends with high sulfur fuel. Since the sulfur concentration in these fuels is strictly monitored at the utility level, the use of utility fuel consumption and sulfur concentration data will result in a controlled inventory. Since the utility sector is the most heavily regulated and uses the large majority of sulfur containing coal and oil, the controlled utility inventory combined with uncontrolled emissions of the remaining sectors will serve as the controlled SO_x inventory. The SO_x inventory presented in Section 5.4, therefore, will reflect the controlled state for all stationary combustion sources.

5.3.3 NO_x Control

To determine the extent of NO_x control for stationary combustion sources, a different approach was used than for particulates and SO_x. In this approach, applicable state and local NO_x regulations (summarized in Section 4.1 of this report) were applied to combustion equipment within the region. Examination of the regulations showed that utility boilers are the most extensively regulated, while gas turbines and large packaged boilers are only regulated in some regions. Examination of data on utility and gas turbine installations and fuel consumption showed that only controls for utility boilers would have greater than a 1 percent effect. Thus, only utility boilers are considered in the following discussion of NO_x controls.

In calculating the effect of NO_x controls on utility boiler emissions, the uncontrolled emissions of a specific boiler were reduced by the ratio of the controlled emission factor to the uncontrolled factor. For example, if the emission limitation for oil-fueled boilers is 129 ng/J and the uncontrolled emission factor is 153 ng/J, then the reduction of NO_x emission (assuming 100 percent compliance) is (1 - 129/153) or 16 percent. A more detailed explanation of the methodology employed to arrive at specific control factors is given in Appendix A. A systematic compilation of stationary source equipment and applicable NO_x regulations yielded the control factors listed in Table 5-16.

TABLE 5-16. NO_x CONTROL FACTORS

	Coal	Oil	Nat. Gas
Tangential	0.000053	0.014	0.057
Wall-Fired	0.0014	0.048	0.124
Horiz. Opposed	0.0014	0.048	0.124
Cyclone	0.0166	0.039	0.0
Vert. and Stoker	0.00005	—	—

Note that the degree of current control of coal-fired utility boilers is small, while those which burn oil or gas are significantly controlled. The control of coal-fired utility boilers is increasing, however, as retrofit controls are being implemented in a number of areas and as new units designed to meet the NSPS (300 ng/J) are being installed. One reason for lack of control of coal-fired boilers is the prior lack of NO_x regulations in states where coal is heavily used, and the comparatively stringent regulations in states which use large amounts of oil and gas. Comparisons of the controlled and uncontrolled NO_x emission rates will be presented in Section 5.4.

5.4 EMISSIONS INVENTORY

This section presents an inventory of major combustion-related pollutants originating from stationary fuel-burning sources of NO_x. The inventory includes the criteria pollutants: NO_x, SO_x, CO, HC, and particulates emitted from gaseous effluent streams. A more complete emissions inventory is given in Appendix A by equipment type for 17 fuel categories and the following noncriteria pollutants: sulfates, trace metallics, POMs and trace elements in hopper and flyash.

5.4.1 Stationary Source Sector Emissions

Tables 5-17 through 5-22 provide 1974 criteria pollutant emissions and totals for the following sectors:

- Utility boilers — Table 5-17
- Packaged boilers — Table 5-18
- Warm air furnaces — Table 5-19
- Gas turbines — Table 5-20
- Reciprocating IC engines — Table 5-21
- Industrial process heating — Table 5-22 (Includes total criteria pollutant emissions for oil- and gas-fired refinery process heaters)

The emission estimates are for 1974 since this is the most recent period for which comprehensive fuel consumption data are availabe. All units are in 1000 Mg per year. Note that these tables give uncontrolled emission figures for NO_x and controlled emission figures for SO_x and particulates.

Table 5-23 summarizes the total emissions from the above sectors.

5.4.2 Controlled NO_x Emissions

Table 5-24 presents the controlled NO_x emissions derived from control factors developed in Section 5.3 for stationary sources. As discussed in that section, controlled NO_x emissions are given for utility boilers only, since gas turbines and packaged boiler NO_x regulations were concluded to have little effect on sector totals. This inventory applies existing 1976 state and local NO_x relations to the 1974 stationary source population. This hybrid inventory is not intended to accurately represent actual NO_x emissions for either year, but merely to indicate the current effect of NO_x emission regulations. The degree of utility boiler control is somewhat uncertain since some units are not in compliance with regulations either through variances or lack of enforcement. Some units, on the other hand, are controlled to levels below the current regulations. In a few areas utilities have added NO_x control, in the absence of regulations, as part of public relation efforts or for energy conservation (low excess air firing). These units have been generally excluded from the controlled boiler inventory.

TABLE 5-17. 1974 CRITERIA POLLUTANT EMISSIONS FOR THE UTILITY BOILER SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Furnace Design	Fuel	NO_x	SO_x	HC	CO	PART
Tangential	Coal	1,409	6,999.6	4.8	58.3	3,178
	Oil	208	583.3	1.36	11.9	30.5
	Gas	146	0.34	0.98	8.2	4.84
Wall-Fired	Coal	946	4,030.6	2.61	64.4	1,734
	Oil	481	598.6	2.15	20.3	31.1
	Gas	738.3	0.74	2.11	28.2	10.5
Opposed Wall	Coal	270.8	1,131.6	0.88	7.55	499
	Oil	177.7	236	0.55	6.9	12.9
	Gas	378.7	0.38	1.07	13.4	5.36
Cyclone	Coal	863.5	2,737.4	10.4	30.0	193
	Oil	16.6	34.9	0.46	1.18	1.74
	Gas	14.7	0.018	0.37	0.44	0.26
Stoker & Vertical	Coal	90.9	414.7	1.63	18.4	263.8
	Oil	—	—	—	—	—
	Gas	—	—	—	—	—
Totals		5,741.2	16,768.2	29.5	269.2	5,965

TABLE 5-18. 1974 CRITERIA POLLUTANT EMISSIONS FOR THE PACKAGE BOILER SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Equipment Design Type	Fuel	NO_x	SO_x	HC	CO	PART
Watertube 29 MW to 73 MW	Coal	290	1,402	3.10	11.7	935.8
	Oil	232.8	269	2.17	2.8	24.3
	Gas	318.5	0.28	3.62	8.4	1.6
Watertube <29 MW	Coal	278.17	2,280	27.66	34.13	2,787.8
	Oil	116.4	298	0.57	2.19	24.1
	Gas	180	5.75	2.87	14.5	2.87
Firetube <29 MW	Coal	107	839	10.1	15.5	1,016
	Oil	429.25	1,048	2.14	8.35	98.7
	Gas	241.7	0.72	4.09	20.69	6.26
Other[a]	Coal	4.48	20.4	8.24	19.7	8.24
	Oil	107.7	242	4.62	28.86	20.8
	Gas	38.98	0.27	2.95	8.61	3.86
Total		2,345	6,405	72.13	175.4	4,930.3

[a] Includes cast iron and residential steam and hot water units

TABLE 5-19. 1974 CRITERIA POLLUTANT EMISSIONS FOR THE WARM AIR FURNACE AND MISC-COMBUSTION SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Equipment	Fuel	NO_x	SO_x	HC	CO	PART
Warm Air Central Furnace	Oil	85.0	152	6.59	43.6	10.8
	Gas	106.3	1.106	10.5	36.9	13.2
Warm Air Room Heater	Oil	44.0	78.4	3.41	22.0	5.58
	Gas	49.5	0.37	4.95	17.3	6.24
Miscellaneous Commercial and Residential Combustion	Gas	34.4	0.258	4.3	12	3.4
Total		320.6	232	29.7	132.6	39.3

TABLE 5-20. 1974 CRITERIA POLLUTANT EMISSIONS FOR THE GAS TURBINE SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Equipment Capacity Range	Fuel	NO_x	SO_x	HC	CO	PART
Gas Turbine >15 MW	Oil	97.4	2.81	2.25	12.4	4.22
	Gas	41.3	0.47	1.81	10.34	1.27
Gas Turbine 4 MW to 15 MW	Oil	211	6.17	5.73	27.2	8.89
	Gas	91.2	1.04	3.84	23.1	2.79
Gas Turbine <4 MW	Oil	0.365	0.0135	0.012	0.047	0.019
	Gas	0.195	0.0026	0.0094	0.049	0.0070
Total		440	10.5	13.7	73.4	17.3

TABLE 5-21. 1974 CRITERIA POLLUTANT EMISSIONS FOR THE RECIPROCATING I.C. ENGINE SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Equipment Capacity Range	Fuel	NO_x	SO_x	HC	CO	PART
I.C. Engines >75 kW/cyl	Oil	94.0	5.10	6.13	16.6	5.56
	Gas	1,262	0.17	451	143	—
	Dual	71.6	—	29.1	9.6	—
I.C. Engines 75 kW to 75 kW/cyl	Oil	224.6	12.3	14.7	40.0	13.1
	Gasoline	100.4	1.36	33.7	1,014.8	1.65
	Gas	66.7	0.0091	23.9	7.6	—
I.C. Engines <75 kW	Gasoline	37.5	0.80	19.6	591.9	0.96
Total		1,857.2	19.6	578.3	1,824	21.5

TABLE 5-22. 1974 CRITERIA POLLUTANT EMISSIONS FOR THE INDUSTRIAL PROCESS HEATING SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Industrial Equipment Category	NO_x	SO_x	HC	CO	PART
Refinery Heaters	147.35	22.67	20.5	—	37.2
Cement Kilns	100.0	392.0	—	—	1126.0
Glass Melting Furnaces	56.7	32.2	—	—	15.2
Glass Annealing Lehrs	10.6	—	—	—	—
Coke Oven Underfire	3.99	161.9	—	—	2,149
Steel Sintering Lines	25.2	34.1	—	1,067.0	485
Open Hearth Furnaces	20.6	22.6	—	—	193.6
Brick & Ceramic Kilns	7.26	16.5	1.26	3.16	2,052.7
Catalytic Cracking	46.0	323.0	144.5	8,969.5	158
Refinery Flares	7.77	—	—	—	—
Iron & Steel Flares	0.32	—	—	—	—
Total	425.8	1,005.0	166.3	10,039.0	6,216.7

TABLE 5-23. CRITERIA POLLUTANT EMISSIONS BY SECTOR (UNCONTROLLED NO_x) 1,000 Mg/yr

Equipment Sector	NO_x	SO_x	HC	CO	PART
Utility Boilers	5,741	16,768	29.5	269.6	5,965
Packaged Boilers	2,345	6,405	72.1	175.4	4,930.3
Warm Air Furnaces and Miscellaneous Combustion	321	232	29.7	133	39.3
Gas Turbines	440	10.5	13.7	73.4	17.3
Reciprocating I.C. Engines	1,857	19.6	578	1,824	21.5
Industrial Process Heating	425.8	1,005	166	10,039	6,216.7
Total	11,130	24,440	889	12,514	17,190

TABLE 5-24. COMPARISON OF CONTROLLED AND UNCONTROLLED STATIONARY SOURCE NO_x EMISSIONS

T-195b

Sector and Equipment Type	Fuel	1974 Controlled NO_x[a] (1,000 Mg/yr)	1974 Uncontrolled NO_x (1,000 Mg/yr)	Percent Reduction (%)
Utility Boilers				
Tangential	Coal	1,408	1,409	0.1
	Oil	205	208	1.4
	Gas	138	146	5.5
Wall-Fired	Coal	945	946	0.1
	Oil	458	481	4.8
	Gas	649	738	12.3
Opposed Wall	Coal	271	271	0
	Oil	169	178	5.1
	Gas	352	379	6.7
Cyclone	Coal	849	863	1.6
	Oil	16	17	6.0
	Gas	15	15	0
Vertical and Stoker	Coal	91	91	0
TOTAL UTILITY	All	5,566	5,741	3.3
Package Boilers	All	2,345	2,345	–
Commercial and Residential Furnaces	All	321	321	–
Gas Turbines	All	440	440	–
IC Engines	All	1,857	1,857	–
Process Heating	All	425.8	425.8	–
TOTAL	All	10,954	11,129	1.7

[a] Controlled by regulations existing December 1976

5.5 SUMMARY AND CONCLUSIONS

This section presents a general summary of the NO_x emissions from all sources and a more detailed summary of the emissions from stationary fuel combustion sources. In addition, several comparisons of the data generated in this study are made with results of previous studies. A comprehensive emission inventory for all pollutants is given in Appendix A.

Conclusions, consisting of rankings of sources on a mass emissions basis and comments on data quality and data gaps, are also presented.

5.5.1 Summary of NO_x Emissions from all Sources

As discussed in Section 2 (Figure 2-1), NO_x emissions result from both natural and anthropogenic sources.

Natural NO_x Emissions

Estimates of biologically-generated natural emissions of oxides of nitrogen range from 175 to 455 Tg (193 to 501 x 10^6 tons) annually on a global basis (References 5-71 through 5-73). Additionally, lightning, the major nonbiological natural source of NO_x, has been estimated to produce about 10 Tg (11 x 10^6 tons) NO per year globally. By contrast, the estimated man-made oxides of nitrogen were 48 Tg per year globally (Reference 5-73). Although man-made emissions are only about 10 percent of total emissions, man-made sources are by far the most significant in air pollution due to their concentration in population centers. This is illustrated by comparison of the ambient concentration due to natural and man-made sources. The natural background ambient NO_2 concentration is estimated at 0.0009 to 0.004 ppm (Reference 5-73). The NO_2 concentration in urban areas, however, is typically between 0.01 to 0.5 ppm. In NO_2-critical areas where the ambient concentration approaches the ambient air quality standard (0.05 ppm), the natural background level is less than 10 percent of the urban ambient concentration.

Anthropogenic NO_x Emissions

As shown in Table 5-25, U.S. man-made NO_x emissions for 1974 total about 21 million metric tons (23 million short tons). The relative contributions of mobile and stationary sources are about 45 and 55 percent, respectively, as illustrated in Figure 5-1. These fractions are calculated using controlled NO_x emissions. If uncontrolled figures for NO_x emissions are used, the respective portions would be 48 percent for mobile and 52 percent for stationary NO_x emissions. Stationary emissions include stationary fuel combustion, noncombustion processes, fugitive and incineration sources.

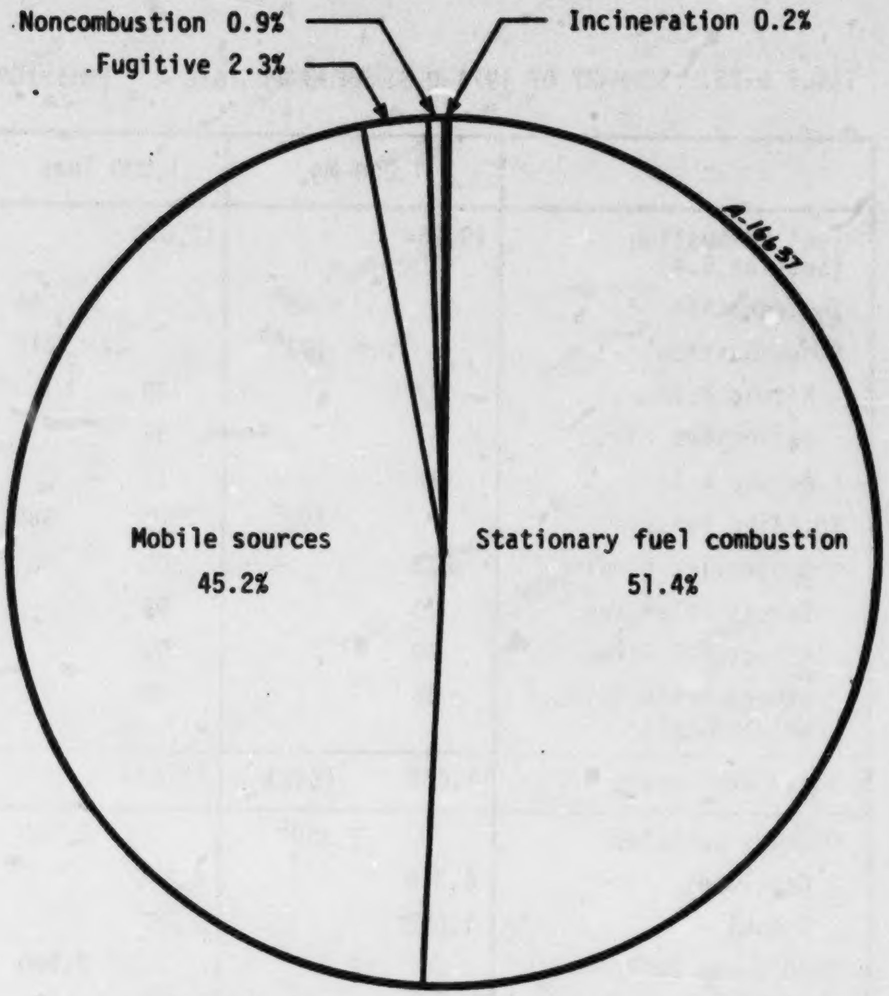
TABLE 5-25. SUMMARY OF 1974 U.S. ANTHROPOGENIC NO_x EMISSIONS

	1,000 Mg		1,000 Tons	
Fuel Combustion (Section 5.4)	10,954		12,070	
Incineration		40[a]		44
Noncombustion		193[ab]		212
Nitric Acid	127		138	
Explosives Mfr	51		56	
Adipic Acid	15		17	
Fugitive Emissions		498[c]		548
Controlled Burning	273		300	
Forest Wildfires	90		99	
Structural Fires	90		99	
Other: Grain Silos, Welding, etc.	45		50	
Total Stationary	11,685	(54%)	12,874	
Highway Vehicles		7,360[c]		8,100
Gasoline	6,310		6,940	
Diesel	1,050		1,160	
Nonhighway Vehicles		2,270[c]		2,500
Aircraft	350		380	
Railroads	90		100	
Vessels	170		190	
Others: Dune Buggies Trail Bikes, Construction Equipment, etc.	1,660		1,830	
Total Mobile		9,630 (46%)		10,600
Total NO_x		21,315		23,474

[a] Reference 5-74

[b] Reference 5-75

[c] Reference 5-76



1974 Stationary Combustion Source NO_x Emissions

	1,000 Mg	1,000 tons	Percent Total
Stationary Fuel Combustion	10,954	12,070	(51.4)
Fugitive Emissions	498	548	(2.3)
Noncombustion	193	212	(0.9)
Incineration	40	44	(0.2)
Mobile Sources	9,630	10,600	(45.2)
TOTAL	21,315	23,474	100

Figure 5-1. Distribution of anthropogenic NO_x emissions for the year 1974 (stationary fuel combustion: controlled NO_x levels).

A detailed listing of stationary NO_x sources is given in Table 5-26 and shown graphically in Figure 5-2. Table 5-26 also gives the contribution of each stationary sector. Note that combustion in stationary sources, the primary emphasis of this program, accounts for about 94 percent of the total emissions from stationary sources. Note also the relative contribution of each fuel. Natural gas accounted for about one-third of the emissions in 1974, with coal accounting for about 40 percent. Preliminary 1976 data show a strong trend away from natural gas fuel in the utility sector.

5.5.2 Summary of Air Pollutant Emissions

Table 5-27 gives emission totals for the criteria pollutants, sulfates, POMs, and preliminary solid and liquid ash stream production. Criteria pollutant data are taken from Section 5.4 and sulfate, POM, and ash production data are from Appendix A. While totals for the criteria pollutants are considered to be reliable, the totals for sulfate, POM, and ash are order-of-magnitude estimates at best. Since the quality of available emission factor data for POMs is poor, POM emissions are given as a range. For the upper extreme of this range, POM emissions were derived from the largest available emission factor, while at the lower extreme, the smallest emission factors were used. All trace element emissions presented in Appendix A are also considered to be order-of-magnitude estimates.

Rankings of equipment type/fuel combinations on a mass emission basis for the criteria pollutants and energy consumption are given in Tables 5-28 through 5-33. The rankings include only the first 30 sources for each pollutant, which in each case includes the major portion of the emissions for that pollutant. Finally, Table 5-33 ranks NO_x emission control equipment, as well as the equipment rank for SO_x, HC, CO, particulates, and fuel consumption.

5.5.3 Comparison with Data

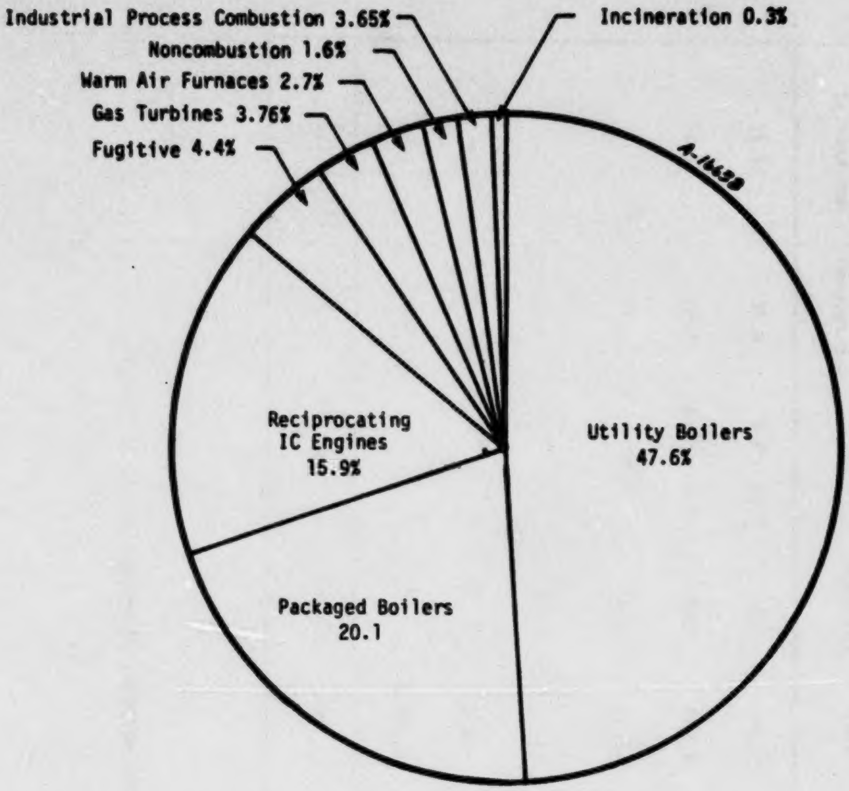
The comparison in Table 5-34 of uncontrolled NO_x emissions developed in this study with estimates of NO_x emissions from other studies is generally favorable. Sector definition was comparable in most cases, with the possible exception of packaged boilers and warm air furnaces. Previous studies did not combine all packaged boilers but separated them by industrial, commercial, and residential application. In addition, space heating was typically used as a sector title under which were combined commercial and residential boilers and warm air furnaces. A further problem with the package boiler sector is the difficulty in obtaining representative data from an essentially unmonitored equipment sector. The lack of real sector data requires the use of broad estimates and results in emission figures of similar quality when compared to the more recent inventories (NO_x Summary and GCA). The present estimates appear very good.

TABLE 5-26. SUMMARY OF 1974 STATIONARY SOURCE NO_x EMISSIONS BY FUEL — 1,000 Mg (Percent of Total)

Sector	Coal	Oil	Gas	Total
Utility Boilers	3,564 (31.0)	848 (7.4)	1156 (10.1)	5566 (47.6)
Packaged Boilers[a]	679.7 (5.9)	886 (7.7)	779 (6.8)	2344.7 (20.1)
Warm Air Furnaces		129 (1.1)	190 (1.6)	320 (2.8)
Gas Turbines		309 (1.9)	133 (1.0)	442 (3.8)
Reciprocating IC Engines	—	456[b] (3.9)	1400 (12.2)	1856 (16.2)
Industrial Process Heating	—	—	—	425.8 (3.64)
Noncombustion	—	—	—	193 (1.7)
Incineration	—	—	—	40 (0.34)
Fugitive	—	—	—	498 (4.3)
Total	4,243.7 (37.0)	2,628 (22.1)	3,658 (31.7)	11,685

[a] Includes steam and hot water commercial and residential heating units

[b] Includes gasoline



1974 Stationary Combustion Source NO_x Emissions

	1,000 Mg	1,000 Tons	Percent Total
Utility Boilers	5,566	6,122	47.6
Packaged Boilers	2,345	2,383	20.1
Warm Air Furnaces	321	353	2.7
Gas Turbines	440	484	3.76
Reciprocating IC Engines	1,857	2,040	15.9
Industrial Process Combustion	425.8	470	3.65
Noncombustion	193	212	1.6
Incineration	40	44	0.3
Fugitive	498	548	4.4
TOTAL	11,685	12,861	100

Figure 5-2. Distribution of stationary anthropogenic NO_x emissions for the year 1974 (stationary fuel combustion: controlled NO_x levels).

TABLE 5-27. 1974 SUMMARY OF AIR AND SOLID POLLUTANT EMISSION FROM STATIONARY FUEL BURNING EQUIPMENT (1,000 Mg)

T-176b

	NO_x[b]	SO_x	HC	CO	Part	Sulfates	POM	Dry Ash Removal	Sluiced Ash Removal
Utility Boilers	5,566	16,768	29.5	270	5,965	231	0.01 – 1.2	6.18	24.78
Packaged Boilers	2,345	6,405	72.1	175	4,930	146	0.2 – 67.8	4.41	1.07
Warm Air Furnaces & Misc. Comb.	321	232	29.7	132.6	39.3	6.4	0.06	--	--
Gas Turbines	440	10.5	13.7	73.4	17.3	a	a	--	--
Recip. IC Engines	1,857	19.6	578	1,824	21.5	a	a	--	--
Process Heating	425.8	1005	166	10,039	6,216.7	a	a	--	--
TOTAL	10,954	24,440	889	12,514	17,190	382	69	--	--

[a] No emission factor available

[b] Controlled NO_x

[c] Based on 80 percent hopper and flyash removal by sluicing methods; 20 percent dry solid removal

TABLE 5-28. FUEL CONSUMPTION RANKING OF STATIONARY COMBUSTION SOURCES

T-177a

	Source	Equipment Type	Fuel	Annual Fuel Consumption (10^{15} kJ)
1	Utility Boilers	Tangential	coal	5.130
2	Warm Air Furnaces	Central	gas	3.091
3	Utility Boilers	Wall-Firing	coal	2.938
4	Package Boilers	Watertube <29 MW	gas	2.820
5	Utility Boilers	Wall-Firing	gas	2.453
6	Utility Boilers	Cyclone Furnace	coal	1.588
7	Package Boilers	Watertube Stoker <29 MW	coal	1.554
8	Utility Boilers	Wall-Firing	oil	1.495
9	Warm Air Furnaces	Space Heater	gas	1.451
10	Warm Air Furnaces	Central	oil	1.405
11	Package Boilers	Firetube Scotch	oil	1.391
12	Utility Boilers	Tangential	oil	1.360
13	Utility Boilers	Tangential	gas	1.340
14	Utility Boilers	Horizontally Opposed	gas	1.258
15	Refinery Heaters	Natural and Forced Draft	gas	1.247
16	Package Boilers	Watertube >29 MW	gas	1.058
17	Package Boilers	Firetube Firebox	oil	1.012
18	Warm Air Furnaces	Misc Combustion	gas	1.0
19	Package Boilers	Firetube Scotch	gas	0.991
20	Package Boilers	Firetube Firebox	gas	0.918
21	Reciprocating IC Engines	>75 kW/cyl	gas	0.887
22	Package Boilers	Res/Com Steam and Hot Water Units	oil	0.880
23	Utility Boilers	Horizontally Opposed	coal	0.839
24	Package Boilers	Res/Com Steam and Hot Water Units	gas	0.737
25	Warm Air Furnaces	Space Heater	oil	0.727
26	Package Boilers	Watertube >29 MW	oil	0.723
27	Package Boilers	Watertube <29 MW	oil	0.698
28	Package Boilers	Firetube HRT	oil	0.633
29	Package Boilers	Firetube Stoker <29 MW	coal	0.598
30	Gas Turbines	4.0 MW to 15 MW	oil	0.579

T-178a

TABLE 5-29. SO_x MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT

	Sector	Equipment Type	Fuel	Annual SO_x Emissions (Mg)
1	Utility Boilers	Tangential	coal	7,000,000
2	Utility Boilers	Wall-Firing	coal	4,031,000
3	Utility Boilers	Cyclone Furnace	coal	2,740,000
4	Package Boilers	Watertube Stoker <29 MW	coal	2,293,410
5	Utility Boilers	Horizontally Opposed	coal	1,130,000
6	Package Boilers	Firetube Stoker <29 MW	coal	876,000
7	Package Boilers	Watertube Stoker >29 MW	coal	775,700
8	Package Boilers	Watertube Wall Firing >29 MW	coal	627,200
9	Utility Boilers	Wall-Firing	oil	600,000
10	Utility Boilers	Tangential	oil	583,300
11	Package Boilers	Firetube Scotch	oil	504,000
12	Utility Boilers	Vertical and Stoker	coal	415,000
13	Industrial Process Combustion	Cement Kilns	—	392,000
14	Package Boilers	Firetube Firebox	oil	337,300
15	Industrial Process Combustion	Catalytic Cracking	—	323,000
16	Package Boilers	Watertube <29 MW	oil	298,000
17	Package Boilers	Watertube >29 MW	oil	297,800
18	Utility Boilers	Horizontally Opposed	oil	236,000
19	Package Boilers	Firetube HRT	oil	207,000
20	Industrial Process Combustion	Coke Oven Underfire	—	162,000
21	Warm Air Furnaces	Central	oil	152,000
22	Package Boilers	Res/Com Steam and Hot Water Unit	oil	128,700
23	Package Boilers	Cast Iron	oil	113,600
24	Warm Air Furnaces	Space Heater	oil	78,000
25	Utility Boilers	Cyclone Furnaces	oil	35,000
26	Package Boilers	Res/Com Steam and Hot Water Unit	coal	34,450
27	Industrial Process Combustion	Steel Sintering Machines	—	34,000
28	Industrial Process Combustion	Glass Melters	—	32,000
29	Industrial Process Combustion	Refinery Heaters	oil	21,000
30	Industrial Process Combustion	Brick Kilns	—	16,500

TABLE 5-30. CO MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT

	Sector	Equipment Type	Fuel	Annual CO Emissions (Mg)
1	Industrial Process Combustion	Catalytic Cracking	—	8,969,000
2	Industrial Process Combustion	Steel Sintering Machines	—	1,067,000
3	Reciprocating IC Engines	75 kW to 75 kW/cyl	gasoline	1,054,800
4	Reciprocating IC Engines	<75 kW	gasoline	592,000
5	Reciprocating IC Engines	>75 kW/cyl	gas	142,850
6	Utility Boilers	Wall-Firing	coal	64,400
7	Utility Boilers	Tangential	coal	58,300
8	Warm Air Furnaces	Central	oil	43,600
9	Reciprocating IC Engines	75 kW to 75 kW/cyl	oil	40,000
10	Warm Air Furnaces	Central	gas	36,918
11	Package Boilers	Watertube Stoker 29 MW	coal	34,130
12	Utility Boilers	Cyclone Furnace	coal	29,673
13	Utility Boilers	Wall-Firing	gas	28,249
14	Package Boilers	Res/Com Steam and Hot Water Unit	oil	27,910
15	Gas Turbines	4 MW to 15 MW	oil	27,156
16	Gas Turbines	4 MW to 15 MW	gas	23,100
17	Warm Air Furnaces	Space Heater	oil	22,000
18	Utility Boilers	Wall-Firing	oil	20,300
19	Package Boilers	Res/Com Steam and Hot Water Unit	coal	19,670
20	Utility Boilers	Vertical and Stoker	coal	18,400
21	Warm Air Furnaces	Space Heater	gas	17,325
22	Reciprocating IC Engines	>75 kW/cyl	oil	16,642
23	Package Boilers	Watertube <105 GJ/hr	gas	14,530
24	Utility Boilers	Horizontally Opposed	gas	13,461
25	Gas Turbine	>15 MW	oil	12,400
26	Warm Air Furnaces	Misc. Comb. & Resid.	gas	12,000
27	Utility Boilers	Tangential	oil	11,900
28	Package Boilers	Watertube Stoker >29 MW	coal	11,650
29	Gas Turbine	>15 MW	gas	10,340
30	Package Boilers	Watertube >29 MW	gas	9,478

T-1796

TABLE 5-31. HC MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT

T-180a

	Sector	Equipment Type	Fuel	Annual HC Emissions (Mg)
1	Reciprocating IC Engines	>75 kW/cyl	gas	483,000
2	Industrial Process Combustion	Catalytic Cracking	—	144,500
3	Reciprocating IC Engines	75 kW to 75 kW/cyl	oil	48,461
4	Package Boilers	Watertube Stoker <29 MW	coal	27,660
5	Reciprocating IC Engines	75 kW to 75 kW/cyl	gas	23,900
6	Reciprocating IC Engines	<75 kW	gas	19,647
7	Industrial Process Combustion	Refinery Heaters Forced & Natural Draft	gas	16,089
8	Warm Air Furnaces	Central	gas	10,548
9	Utility Boilers	Cyclone Furnace	coal	10,393
10	Package Boilers	Firetube Stoker	coal	10,130
11	Package Boilers	Res/Com Steam and Hot Water Unit	coal	8,238
12	Warm Air Furnaces	Central	oil	6,593
13	Reciprocating IC Engines	>75 kW/cyl	oil	6,127
14	Gas Turbines	4 MW to 15 MW	oil	5,730
15	Warm Air Furnaces	Space Heater	gas	4,950
16	Utility Boilers	Tangential	coal	4,800
17	Package Boilers	Res/Com Steam and Hot Water Unit	oil	4,542
18	Industrial Process Combustion	Refinery Heaters Natural & Forced Draft	oil	4,426
19	Package Boilers	Watertube >29 MW	gas	4,126
20	Gas Turbines	4 MW to 15 MW	gas	3,840
21	Warm Air Furnaces	Space Heater	oil	3,411
22	Package Boilers	Watertube <29 MW	gas	2,870
23	Utility Boilers	Wall-Firing	coal	2,610
24	Package Boilers	Res/Com Steam and Hot Water Unit	gas	2,506
25	Gas Turbines	>15 MW	oil	2,251
26	Package Boilers	Watertube >29 MW	oil	2,157
27	Utility Boilers	Wall-Firing	oil	2,150
28	Utility Boilers	Wall-Firing	gas	2,110
29	Package Boilers	Watertube Stoker >29 MW	coal	2,004
30	Gas Turbines	>15 MW	gas	1,810

TABLE 5-32. PARTICULATE MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT

T-181a

	Sector	Equipment Type	Fuel	Annual Particulate Emissions (Mg)
1	Package Boilers	Watertube Stoker <29 MW	coal	3,252,000
2	Utility Boilers	Tangential	coal	3,178,000
3	Industrial Process Combustion	Coke Oven Underfire	—	2,149,000
4	Industrial Process Combustion	Brick Kilns	—	2,052,700
5	Utility Boilers	Wall-Fired	coal	1,734,000
6	Package Boilers	Firetube Stoker	coal	1,202,000
7	Industrial Process Combustion	Cement Kilns	—	1,126,000
8	Utility Boilers	Horizontal Opposed Wall	coal	499,000
9	Package Boilers	Watertube Stoker >29 MW	coal	488,600
10	Industrial Process Combustion	Steel Sintering Machines	—	485,000
11	Package Boilers	Watertube, Wall Fired >29 MW	coal	436,400
12	Utility Boilers	Vertical and Stoker	coal	263,800
13	Industrial Process Combustion	Open Hearth Furnace	—	193,600
14	Utility Boilers	Cyclone Furnace	coal	193,000
15	Industrial Process Combustion	Catalytic Cracking	—	158,000
16	Industrial Process Combustion	Steel Sintering Machines	—	48,500
17	Package Boilers	Firetube Scotch	oil	40,210
18	Package Boilers	Firetube HRT	oil	31,740
19	Utility Boilers	Wall-Firing	oil	31,100
20	Utility Boilers	Tangential	oil	31,100
21	Package Boilers	Firetube Firebox	oil	26,750
22	Industrial Process Combustion	Forced & Natural Draft Refinery Heaters	oil	26,429
23	Package Boilers	Watertube, Wall-Fired >29 MW	oil	24,320
24	Package Boilers	Watertube <29 MW	oil	22,950
25	Industrial Process Combustion	Glass Melters	—	15,210
26	Warm Air Furnaces	Central	gas	13,185
27	Reciprocating IC Engines	75 kW to 75 kW/cyl	oil	13,132
28	Utility Boilers	Horizontally Opposed	oil	12,852
29	Package Boilers	Res/Com Steam and Hot Water Unit	oil	12,500
30	Warm Air Furnaces	Central	oil	10,789
31	Industrial Process Combustion	Forced & Natural Draft Refinery Heaters	gas	10,726

T-182b

TABLE 5-33. NO_x MASS EMISSION RANKING OF STATIONARY COMBUSTION EQUIPMENT AND CRITERIA POLLUTANT AND FUEL USE CROSS RANKING

Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	Cumulative (Mg)	Cumulative (Percent)	Fuel Rank	SO_x Rank	CO Rank	HC Rank	Part Rank
1 Utility Boilers	Tangential	Coal	1,410,000	1,410,000	13.1	1	1	7	16	2
2 Reciprocating IC Engines	>75 kW/cyl	Gas	1,262,000	2,672,000	24.8	21	>30	4	1	>30
3 Utility Boilers	Wall Firing	Coal	946,000	3,618,000	33.5	3	2	6	23	5
4 Utility Boilers	Cyclone Furnace	Coal	863,500	4,481,500	41.5	6	3	12	9	13
5 Utility Boilers	Wall Firing	Gas	738,300	5,219,800	48.4	4	>30	13	28	>30
6 Utility Boilers	Wall Firing	Oil	481,000	5,700,800	52.8	8	9	17	27	18
7 Utility Boilers	Horizontally Opposed	Gas	378,700	6,079,500	56.3	14	>30	24	>30	>30
8 Reciprocating IC Engines	75 kW to 75 kW/cyl	Oil	325,000	6,404,500	59.4	>30	>30	3	3	26
9 Packaged Boilers	Watertube >29 MW	Gas	318,500	6,723,000	62.3	16	>30	29	19	>30
10 Packaged Boilers	Watertube Stoker <29 MW	Coal	278,170	7,001,170	64.9	7	4	11	4	1
11 Utility Boilers	Horizontally Opposed	Coal	270,800	7,271,970	67.4	23	5	>30	>30	7
12 Packaged Boilers	Watertube >29 MW	Oil	232,480	7,504,450	69.5	26	16	>30	26	22
13 Utility Boilers	Tangential	Oil	208,000	7,712,450	71.5	12	10	27	>30	19
14 Packaged Boilers	Firetube Scotch	Oil	203,990	7,916,440	73.4	11	11	>30	>30	16
15 Packaged Boilers	Watertube <29 MW	Gas	180,000	8,096,440	75.0	5	>30	>30	22	>30
16 Utility Boilers	Horizontally Opposed	Oil	177,900	8,274,340	76.7	>30	17	>30	>30	27
17 Packaged Boilers	Watertube <29 MW	Coal	164,220	8,438,560	78.2	>30	8	>30	>30	9
18 Industrial Process Comb.	Forced & Natural Draft Refinery Heaters	Oil	147,350	8,585,910	79.6	>30	29	>30	18	21
19 Utility Boilers	Tangential	Gas	146,000	8,731,910	80.9	13	>30	>30	>30	>30
20 Packaged Boilers	Firetube Firebox	Oil	139,260	8.871,170	82.2	17	13	>30	>30	20

TABLE 5-33. Concluded

Sector	Equipment Type	Fuel	Annual NO_x Emissions (Mg)	Cumulative (Mg)	Cumulative (Percent)	Fuel Rank	SO_x Rank	CO Rank	HC Rank	Part Rank
21 Packaged Boilers	Watertube Stoker	Coal	125,350	8,996,520	83.4	>30	7	28	29	8
22 Gas Turbines	4 to 15 MW	Oil	118,500	9,115,020	84.5	30	>30	15	14	>30
23 Packaged Boilers	Watertube <29 MW	Oil	116,430	9,231,450	85.6	27	15	>30	>30	23
24 Warm Air Furnaces	Central	Gas	106,300	9,337,750	86.5	2	>30	10	8	25
25 Packaged Boilers	Firetube Stoker <29 MW	Coal	102,040	9,439,790	87.5	29	6	>30	10	6
26 Packaged Boilers	Firetube Scotch	Gas	98,010	9,537,800	88.4	19	>30	>30	>30	>30
27 Gas Turbines	>15 MW	Oil	97,400	9,635,200	89.3	>30	>30	>30	30	>30
28 Reciprocating IC Engines	>75 kW/cyl	Oil	94,000	9,729,200	90.2	>30	>30	22	13	>30
29 Industrial Process Comb.	Forced & Natural Draft Refinery Heaters	Gas	92,608	9,821,808	91.0	15	>30	>30	7	30
30 Utility Boilers	Vertical and Stoker	Coal	90,900	9,912,708	91.9	>30	12	>20	>30	>10

TABLE 5-34. COMPARISON OF STATIONARY UNCONTROLLED NO_x EMISSIONS (1,000 Mg)

Sector	ESSO[a] (1968)	AP-115[b] (1970)	OAQPS[c] (1971)	NO_x[d] Summary (1972)	GCA[e] (1973)	OAQPS[f] (1974)	Current (1974)
Utility Boilers	3,490	4,282	4,891	5,155	5,909	10,000	5,741
Packaged Boilers	3,463	4,327	4,078	2,245	2,009		2,345
Warm Air Furnaces	909[A]	518[A]	533[A]	427[A]	291[A]		320.6
Gas Turbines	B	E	E	264	446		440
Reciprocating IC Engines	1,909[C]	E	E	1,990	1,491		1,857.2
Process Heating	B	182	B	355	---		425.8
Noncombustion	218	---	182	135	---	550[F]	193
Incineration	B	73	36	36	15	91[G]	40
Other	D	D		D		91	---
Total	9,989	9,382	9,720	10,607	10,161	10,732	11,363

A — Also includes steam and hot water units
B — Included in packaged boilers
C — Pipeline and gas plants only
D — Not included in data
E — Included in utility and packaged boilers depending on use
F — Includes all petroleum industry emissions
G — Includes all solid waste disposal

[a] Reference 5-76
[b] Reference 5-77
[c] Reference 5-74
[d] Reference 5-78
[e] Reference 5-6
[f] Reference 5-79

Table 5-35 compares the energy consumption figures developed in this study to those of other studies. Again the overall comparison is favorable, although direct comparisons cannot be made in some cases because of differences in sector definition.

Table 5-36 compares criteria pollutant emissions developed in this study to those of OAQPS and NEDS. In general, comparisons are favorable. The only significant difference is in the CO estimate. Examination of the CO estimates in this report indicates that nearly 24 percent of these emissions result from gasoline-fueled reciprocating IC engines of less than <75 kW (15 hp), and about 41 percent of the total are from medium capacity gasoline engines. Because of the nature of the IC engine population — especially units of this capacity range — comprehensive reporting of real data is difficult to achieve. This may explain the discrepancy between an inventory compiled partially through estimates of fuel consumption and generation and an inventory relying essentially on reported data.

5.5.4 Conclusion

The current inventory of stationary combustion-related pollutants concentrated primarily on the criteria air pollutants. Estimates of nationwide SO_x and particulate emissions reflected present control implementation and regulations; NO_x emission estimates were given in both the uncontrolled and controlled states. Mass emission rankings of stationary combustion equipment for the criteria pollutants indicate the relative importance of NO_x sources with respect to SO_x, CO, HC, and particulate emissions. In general, the criteria pollutant inventory is considered to be of relatively high quality in terms of emission totals. In terms of sector emissions, however, the quality ranges from good for utility boilers; fair to good for the warm air furnace, gas turbine, and reciprocating IC engine sectors, to poor for the package boiler and industrial process heating sectors. Secondary emphasis was placed on all other multimedia pollutants. The preliminary estimates of sulfates, POMs, and trace element emissions are poor in quality as a result of very sparse and inconsistent data. Liquid and solid stream combustion-related pollutant (trace elements) emissions are also of very poor quality, partly due to the unavailability of exact fuel composition monitoring. Several comments can be made about the quality of the inventory or pollutant data:

- The packaged boiler sector is the most difficult to quantify in terms of fuel consumption, equipment emission factors and emissions. This is due to the large capacity range of the equipment sector, the diversity of equipment design, and the extremely large population of this sector.
- The industrial process combustion sector is also extremely difficult to quantify. The difficulty arises from the lack of specific fuel and fuel consumption data combined with

TABLE 5-35. COMPARISON OF STATIONARY SOURCE ANNUAL FUEL CONSUMPTION ESTIMATES (10^{15} kJ)

Sector	OAQPS[a] (1971)	AP-115[b] (1969)	NO_x[c] Summary (1972)	GCA[d] (1973)	Current (1974)
Utility Boilers	14.81	12.81	15.59	15.61	19.22
Packaged Boilers	30.66 A	29.20 A	16.81	13.42	15.573 B
Warm Air Furnaces	—	—	10.43 B	8.36 B	6.674
Gas Turbines	—	—	0.939	1.42	1.525
Reciprocating IC Engines	—	—	1.33	2.12	1.240
Total	45.47	42.01	45.1	40.93	44.234

A — Includes IC engines and warm air furnaces
B — Includes steam and hot water units

[a] Reference 5-74
[b] Reference 5-77
[c] Reference 5-78
[d] Reference 5-6

TABLE 5-36. COMPARISON OF CURRENT STATIONARY EMISSION ESTIMATES DATA WITH PREVIOUS STUDIES (1,000 Mg)

Pollutant	OAQPS[a] (1974)	NEDS[b] (1976)	OAQPS[c] (1974)	Current (1974)
NO_x	12.36^A	11.79^A	10.45^A	11.36^{AD}
SO_x	22.91^B	24.35^B	21.36^A	23.44^C
HC	1.55^B	0.46^B	1.7^B	0.72^C
CO	1.27^B	1.29^B	0.9^B	2.48^C
Particulates	8.00^B	6.47^B	5.9	10.97^C

A — Total minus transportation
B — Stationary fuel combustion only
C — Fuel combustion minus process heating
D — Controlled NO_x estimates

[a] Reference 5-80

[b] Reference 5-81

[c] Reference 5-79

the large number of process heating applications, the variation of equipment design and the variation in combustion practices from industry to industry.

- POM emissions were treated as a single pollutant because few data were available for specific POM compounds. Even the available POM data exhibited large scatter which warranted reporting ranges of emission factors and emission rates. Extensive testing is needed in all sectors.
- Transient or nonconventional operations and their effect on multimedia emission rate were treated only superficially. Test data were essentially unavailable except in the space heating applications where some testing has occurred. Test data are needed before further quantification can proceed.

The compilation of this inventory indicated many areas where further data are necessary to improve the quality of this and the subsequent projections which will result from this inventory:

- Utility Boilers
  - An extensive geographic population distribution by equipment design and fuel
  - Further data on noncriteria pollutant emission factors (sulfate, POM and POM subcategories, and trace elements)
  - Comprehensive monitoring of the trace metal content of fuels
  - More conclusive data on the speciation of trace element emissions
  - Comprehensive testing of liquid and solid effluent streams to identify and quantify combustion-related pollutants
  - Test data on the effect of nonstandard operation on the composition of multimedia effluent streams
- Package Boilers
  - Extensive inventories of population by equipment design, fuel capabilities and consumption, capacity, location, and application
  - Extensive emission characteristics of the majority of equipment design presently available
  - Test data on the effect of nonstandard operation on multimedia effluent stream composition

- Warm Air Furnaces
  - Data on noncriteria pollutant formation characteristics
  - More comprehensive emission factor data for the range of available designs
  - Extensive data on the effect of cyclic operation on effluent stream composition
- Gas Turbines
  - Extensive data on simple, regenerative, and combined cycle population as a function of capacity, fuel, application, and location
  - Test data on noncriteria pollutant formation characteristics
- Reciprocating IC Engines
  - Extensive data on equipment distribution by design, fuel, application, and location
  - Data on noncriteria pollutant formation characteristics
- Industrial Process Combustion
  - Comprehensive inventorying of process combustion sources in terms of function, capacity, fuel, and equipment design
  - Data on process fuel consumption for use with emission factors
  - Data on emission characteristics with process gas fuels
  - Data on noncriteria pollutant formation characteristics

Subsequent updates to the inventory will improve the estimates of noncriteria pollutants and liquid and solid effluents pending new test results. This inventory will then act as a basis for a comprehensive assessment of the pollution potential of stationary sources of NO_x. This will be accomplished by integrating two intermediate tasks: (1) a fuel use and emission projection to the year 2000 and (2) the development of regional and AQCR emission inventories. The assessment of pollution potential will be used in assessing baseline and controlled environmental impacts of NO_x controls in Task B5.

REFERENCES FOR SECTION 5

5-1. Dupree, W. G., and J. S. Corsentino, "Energy Through the Year 2000 (Revised)," U.S. Bureau of Mines, December 1975.

5-2. Mezey, E. J., et al., "Fuel Contaminants, Volume I, Chemistry," EPA 600/2-76-177a, NTIS-PB 256 020/AS, Battelle-Columbus Laboratories, July 1976.

5-3. FPC News, Vol. 8, No. 13, March 28, 1975.

5-4. Ctvrtnicek, T., "Evaluation of Low Sulfur Western Coal Characteristics, Utilization, and Combustion Experience," EPA 650/2-75-046, NTIS-PB 243 911/AS, May 1975.

5-5. "Coal-Fired Power Plant Trace Element Study — A Three-Station Comparison," Radian Corporation, EPA Region VIII, September 1975.

5-6. Surprenant, Norman, et al., "Preliminary Emissions Assessment of Conventional Stationary Combustion Systems, Volume II," EPA 600/2-76-046b, NTIS-PB 252 175/AS, March 1976.

5-7. Ruch, R. R., et al., "Occurrence and Distribution of Potentially Volatile Trace Elements in Coal," EPA 650/2-74-054, NTIS-PB 238 091/AS.

5-8. Magee, E. M., et al., "Potential Pollutants in Fossil Fuels," EPA-R2-73-249, NTIS-PB 225 039/7AS, June 1973.

5-9. Vitez, B., "Trace Elements in Flue Gases and Air Quality Criteria," Vol. 80, No. 1, Power Engineering, January 1976.

5-10. FPC News, Vol. 8, No. 23, June 6, 1975.

5-11. "Applicability of NO_x Combustion Modifications to Cyclone Boilers (Furnaces)," Monsanto Research Corporation, (Draft) 1976.

5-12. "Standard Support and Environmental Impact Statement for Standards of Performance: Lignite-Fired Steam Generators," (Draft), A. D. Little, Inc., Office of Air Quality Planning and Standards, March 1975.

5-13. Smith, D. W., et al., "Electric Utilities and Equipment Manufacturers' Factors in Acceptance of Advanced Energy," A.D. Little, Inc., ADL-77771, September 1975.

5-14. Putnam, A. A., et al., "Evaluation of National Boiler Inventory," Battelle-Columbus Laboratories, EPA 600/2-75-067, NTIS-PB 248 100/AS, October 1975.

5-15. "Minerals Yearbook 1973 — Metals, Minerals, and Fuels, Volume I," U.S. Bureau of Mines.

5-16. Power Magazine, Plant Design Issues, 1971 through 1976.

5-17. FPC News, Vol. 9, No. 3, January 16, 1976.

5-18. Locklin, D. W., et al., "Design Trends and Operating Problems in Combustion Modification of Industrial Boilers," EPA 650/2-74-032, NTIS-PB 235 712/AS, Battelle-Columbus Laboratories, April 1974.

5-19. "Current Industrial Reports, Steel Power Boilers," 1968 through 1975, U.S. Department of Commerce, Bureau of the Census.

5-20. Hopper, T. G., et al., "Impact of New Source Performance Standards of 1985 National Emissions from Stationary Sources," Volume I, Final Report, The Research Corporation of New England, October 1975.

5-21. "Statistical Abstract of the United States 1975," (86th Annual Edition), U.S. Department of Commerce, Bureau of the Census, 1975.

5-22. Durkee, K. R., et al., "Standards Support and Environmental Impact Statement — An Investigation of the Best Systems of Emission Reduction for Stationary Gas Turbines," EPA, July 1976.

5-23. "Gas Turbine Electric Plant Construction Cost and Annual Production Expenses, First Annual Publication — 1972," FPC S-240, Federal Power Commission, 1972.

5-24. "1975 Sawyer's Gas Turbine Catalog," Gas Turbine Publications, Incorporated, Stamford, Connecticut, 1975.

5-25. "Gas Turbines in U.S. Electrical Utilities," Gas Turbine International, March through June 1976.

5-26. Offen, G. R., et al., "Standard Support Document and Environmental Impact Statement — Reciprocating Internal Combustion Engines," Aerotherm Project 7152, Acurex Corporation, November 1975.

5-27. Goldish, J., et al., "Systems Study of Conventional Combustion Sources in the Iron and Steel Industry," EPA-R2-73-192, NTIS-PB 226 294/AS, April 1973.

5-28. Ketels, P. A., et al., "A Survey of Emissions Control and Combustion Equipment Data in Industrial Process Heating," Institute of Gas Technology, June 1976.

5-29. Klett, M. G., and J. B. Galeski, "Flare Systems Study," Lockheed Missiles and Space Co., Inc., EPA 600/2-76-079, NTIS-PB 251 664/AS, March 1976.

5-30. Personal communication with K. Hunter of KVB, Inc., principal contributor to American Petroleum Institute Study scheduled for release in September 1977.

5-31. "Compilation of Air Pollutant Emission Factors (Second Edition)," U.S. Environmental Protection Agency, AP-42, April 1973.

5-32. "Supplement No. 6 for Compilation of Air Pollutant Emission Factors (Second Edition)," U.S. Environmental Protection Agency, Office of Air and Waste Management, Office of Air Quality Planning and Standards, April 1976.

5-33. "Supplement No. 3 for Compilation of Air Pollutant Emission Factors (Second Edition)," U.S. Environmental Protection Agency, Office of Air and Waste Management, Office of Air Quality Planning and Standards, July 1974.

5-34. "Proceedings of the Stationary Source Combustion Symposium, Volume III — Field Testing and Surveys," EPA 600/2-76-152c, NTIS-PB 257 146/AS, June 1976.

5-35. "Proceedings of the Stationary Source Combustion Symposium, Volume II — Fuels and Process Research and Development," EPA 600/2-76-152b, NTIS-PB 256 321/AS, June 1976.

5-36. Bartok, W., et al., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions for Utility Boilers," Exxon Research and Engineering Company, EPA 650/2-74-066, NTIS-PB 237 344/AS, June 1974.

5-37. Bartok, W., et al., "Systematic Field Study of NO_x Emission Control Methods for Utility Boilers," GRU.4GNOS.71, Esso Research and Engineering, Office of Air Programs, Environmental Protection Agency, December 1971.

5-38. Selker, Ambrose P., "Program for Reduction of NO_x from Tangential Coal-Fired Boilers, Phase II," Combustion Engineering, Inc., EPA 650/2-73-005a, NTIS-PB 245 162/AS, June 1975.

5-39. Selker, Ambrose P., "Program for Reduction of NO_x from Tangential Coal-Fired Boilers, Phase IIa," Combustion Engineering, Inc., EPA 650/2-73-005b, NTIS-PB 246 889/AS, August 1975.

5-40. McCann, C., et al., "Combustion Control of Pollutants from Multiburner Coal-Fired Systems," U.S. Bureau of Mines, EPA 650/2-74-038, NTIS-PB 233 037/AS, May 1974.

5-41. "The Proceedings of the NO_x Control Technology Seminar," San Francisco, California, February 1976, Electric Power Research Institute, SR-39.

5-42. "Sources of Polynuclear Hydrocarbons in the Atmosphere," U.S. Department of Health, Education and Welfare, AP-33.

5-43. Homolya, J. B., et al., "A Characterization of the Gaseous Sulfur Emissions from Coal and Coal-Fired Boilers," presented at the Fourth National Conference on Energy and the Environment, October 1976, Cincinnati, Ohio.

5-44. Klein, David H., et al., "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plant," Environmental Science and Technology. Vol. 9, No. 10, pp. 973-979, October 1975.

5-45. "Trace Elements in a Combustion System," Battelle-Columbus Laboratories, EPRI Final Report 122-1, January 1975.

5-46. Lee, R. E., Jr., "Concentration and Size of Trace Metal Emissions from a Power Plant, a Steel Plant, and a Cotton Gin," Environmental Science and Technology, Vol. 9, No. 7, pp. 643-647.

5-47. Davison, Richard L., et al., "Trace Elements in Fly Ash — Dependence of Concentration on Particle Size," Environmental Science and Technology, Vol. 9, No. 13, pp. 1107-1113, December 1974.

5-48. Kaakinen, J. W., et al., "Trace Element Behavior in Coal-Fired Power Plant," Environmental Science and Technology, Vol. 9, No. 9, pp. 862-869, September 1975.

5-49. Cato, G. A., et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers — Phase I," KVB Engineering, Inc., EPA-650/2-74-078a, NTIS-PB 238 920/AS, October 1974.

5-50. Cato, G. A., et al., "Field Testing: Application of Combustion Modifications Control to Pollutant Emissions from Industrial Boilers — Phase II," KVB Engineering, Inc., EPA-600/2-76-086a, NTIS-PB 253 500/AS, April 1976.

5-51. Cato, G. A., "Field Testing: Trace Element and Organic Emissions from Industrial Boilers," KVB Engineering, Inc., EPA-600/2-76-086b, NTIS-PB 261 263/AS, October 1976.

5-52. Barrett, R. E., et al., "Field Investigation of Emissions from Combustion Equipment for Space Heating," Battelle-Columbus Laboratories, EPA-R2-73-084a, NTIS-PB 223 148, June 1973.

5-53. Levy, A., et al., "Research Report on a Field Investigation of Emissions from Fuel Oil Combustion for Space Heating," Battelle-Columbus Laboratories, American Petroleum Institute, November 1971.

5-54. Hall, Robert E., "The Effect of Water/Distillate Oil Emulsions on Pollutants and Efficiency of Residential and Commercial Heating Systems," APCA Paper No. 75-09.4, 68th Annual Meeting of the Air Pollution Control Association, Boston, Massachusetts, June 1975.

5-55. Giammar, R. D., et al., "The Effect of Additives in Reducing Particulate Emissions from Residual Oil Combustion," ASME 75-wa/CD-7.

5-56. Giammar, R. D., et al., "Particulate and POM Emissions from a Small Commercial Stoker-Fired Boiler Firing Several Coals," Paper No. 76-4.2, 69th Annual Meeting of the Air Pollution Control Association, Portland, Oregon, June 1976.

5-57. Hall, R. E., et al., "Study of Air Pollutant Emissions from Residential Heating Systems," EPA-650/2-74-003, NTIS-PB 229 697/AS, January 1974.

5-58. Brown, R. A., et al., "Feasibility of a Heat and Emission Loss Prevention System for Area Source Furnaces," Acurex Corporation, EPA-600/2-76-097, NTIS-PB 253 945/AS, April 1976.

5-59. Offen, G. R., et al., "Control of Particulate Matter from Oil Burners and Boilers," Acurex Corporation, EPA-450/3-76-005, April 1976.

5-60. Hare, Charles T., et al., "Exhaust Emissions from Uncontrolled Vehicles and Related Equipment Using Internal Combustion Engines, Part 6: Gas Turbine Electric Utility Power Plants," Southwest Research Institute, Environmental Protection Agency, February 1974.

5-61. "Supplement No. 4 for Compilation of Air Pollutant Emission Factors (Second Edition)," U.S. Environmental Protection Agency, Office of Air and Waste Management, Office of Air Quality Planning and Standards, January 1975.

5-62. Dietzmann, H. E., and K. J. Springer, "Exhaust Emissions from Piston and Gas Turbine Engines Used in Natural Gas Transmission," Southwest Research Institute, AR-923, January 1974.

5-63. Hare, C. T., and K. J. Springer, "Exhaust Emissions from Uncontrolled Vehicles and Related Equipment Using Internal Combustion Engines. Final Report, Part 5: Heavy-Duty Farm, Construction, and Industrial Engines," Southwest Research Institute, October 1973.

5-64. Richards, J., and R. Gerstle, "Stationary Source Control Aspects of Ambient Sulfates: A Data-Based Assessment," (unpublished draft report) EPA Contract No. 68-02-1321, PedCo Environmental Specialists, Inc., February 1976.

5-65. "Hydrocarbon Pollutant Systems Study, Volume 1 — Stationary Sources, Effects, and Control," MSA Research Corporation, NTIS-PB 219 073, October 1972.

5-66. Information from National Emissions Data System (NEDS), August 28, 1973.

5-67. Information from National Emissions Data System (NEDS), May 15, 1974.

5-68. Personal communication with Robert D. MacLean, Portland Cement Manufacturer's Association, January 1977.

5-69. "Flue Gas Desulfurization Survey July-August 1976," PedCo Environmental, Cincinnati, Ohio.

5-70. "The West Scrubber Newsletter," No. 2-28, The McIlvaine Company, Northbrook, Illinois, October 31, 1976.

5-71. Robinson, E., and R. C. Robbins, Journal of the Air Pollution Control Association, pp. 20 and 303, 1970.

5-72. Skinner, K. J., "Nitrogen Fixation," Chemical and Engineering News, October 1976.

5-73. "Air Quality and Stationary Source Emissions Control," A Report by the Commission on Natural Resources, National Academy of Sciences, National Academy of Engineering, and National Research Council, Serial 94-4, March 1975.

5-74. "OAQPS Data File of Nationwide Emissions, 1971," Office of Air Quality Planning and Standards, EPA, May 1973.

5-75. "Annual Survey of Manufacturers 1974 — Fuels and Electric Energy Consumed," U.S. Department of Commerce, Bureau of the Census.

5-76. Bartok, W., et al., "Systems Study of Nitrogen Oxide Control Methods for Stationary Sources, Volume II," prepared for National Air Pollution Control Administration, NTIS-PB 192 789, Esso Research and Engineering, 1969.

5-77. Cavender, J. H., et al., "Nationwide Air Pollutant Emission Trends 1940-1970," Publication No. AP-115, EPA, January 1973.

5-78. Shimizu, A. B., et al., "NO_x Combustion Control Methods and Costs for Stationary Sources; Summary Study," EPA-600/2-75-046, NTIS-PB 246 750/AS, September 1975.

5-79. "Monitoring and Air Quality Trends Report, 1974," EPA-450/10-76-001 EPA Office of Air Quality Planning and Standards, February 1976.

5-80. Personal communication with C. Masser, National Emissions Data System (NEDS), October 1976.

5-81. Information from National Emissions Data System (NEDS), October 26, 1976.

SECTION 6

EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS

Modification of the combustion process for NO_x control can also potentially change emissions of other combustion-generated pollutants. If unchecked, these potential changes, referred to as incremental emissions, may have an adverse effect on the environment, the unit thermal efficiency, or the overall system performance. Since the incremental emissions are sensitive to the same combustion conditions as NO_x, they may, with proper engineering, be held to acceptable levels, or even reduced, during control development so that the net environmental benefit is maximized. In fact, control of incremental emissions of carbon monoxide, hydrocarbons and smoke has been a key part of all past NO_x control development programs. Recent control development gives increased attention to other potential pollutants such as sulfates, organics, and trace metals. The NO_x E/A is quantifying incremental emission rates and impacts to enable subsequent control development to constrain any adverse impacts of NO_x controls to acceptable levels.

This section gives a preliminary evaluation of the demonstrated and potential effects of combustion modification NO_x controls on incremental emissions. The results will serve to scope and guide priorities for subsequent NO_x E/A efforts in incremental emission data compilation, impact characterization, and control process studies. Attention is focused on flue gas emissions from the major sources using near-term NO_x controls, since these situations are the most important in the program and are the only ones for which any significant data exist. Subsequent effort will consider liquid and solid effluents, minor sources and alternate or advanced NO_x controls. Also, the discussion here is concerned only with estimating incremental emission rates without regard to potential impact. Ultimately, the significance of the incremental emission depends on the baseline uncontrolled pollutant emission rates (discussed in Section 5) and the maximum acceptable ambient pollutant concentration (discussed in Section 3) as well as other factors such as pollutant transport and transformation. Preliminary screening of potential incremental impacts due to NO_x controls, considering these factors, is addressed in Section 7.3.

The preliminary evaluation in this section first screens the matrix of control techniques/pollutant pairs to identify potential incremental emission problems. The currently available data on the effects of NO_x controls on residual emissions are then summarized and discussed in terms of verifying preliminary expectations. Areas of insufficient data are identified and the relative importance of obtaining requisite data is assessed. Finally, the areas where future NO_x E/A efforts should be concentrated are identified and ranked in order of importance.

In the discussion that follows, Section 6.1 describes the preliminary control technique/pollutant screening task. Here changes in the levels of incremental emissions are qualitatively linked to the combustion conditions resulting from the use of specific NO_x controls. Areas of potential concern, in which an emission increase can be expected, are also noted. Section 6.2 presents and evaluates the available data documenting emission changes on a pollutant-by-pollutant basis. Postulated areas of concern are substantiated, where possible, and areas of insufficient data are noted. Where insufficient data exist, further discussions of appropriate pollutant formation mechanisms and their implications are presented.

Based on Sections 6.1 and 6.2, Section 6.3 groups control technique/pollutant pairs into areas of:

- High potential emissions impact, where well-documented data indicate that a particular control causes significant increases in emissions of a certain pollutant
- Intermediate potential emissions impact, where basic principles indicate that a particular control is expected to increase a given emission, but supporting data are missing
- Low potential emissions impact, where the data show that emissions are unaffected or decreased when using a given control, or when basic formation mechanisms clearly indicate the same conclusion

Areas of high and intermediate potential impact are prioritized for future E/A consideration and elucidation. Areas of low potential impact will be accorded lower priority in subsequent E/A efforts.

6.1 PRELIMINARY SCREENING

To evaluate incremental emissions due to applying combustion modification NO_x controls, it is helpful to first outline the areas where expected adverse effects on emission levels may occur. Such an approach requires linking the NO_x control-induced combustion conditions to the expected changes in emission levels through pollutant formation mechanisms. This is accomplished in Section 6.1.1 which addresses combustion modifications applied to boilers; in Section 6.1.2 which treats combustion NO_x controls applicable to stationary internal combustion (IC) engines and gas turbines; and in Section 6.1.3 which reviews the data for warm air furnaces. The discussion is separated in this manner because the specific methods used to achieve low-NO_x formation conditions differ significantly between these equipment classes. This is true even though the desired low-NO_x combustion conditions may be similar from equipment class to class.

Each of the following subsections:

- Lists the set of NO_x combustion controls appropriate to the given equipment class
- Lists the altered combustion conditions resulting from imposing each control
- Postulates the effect of each combustion condition on the level and speciation of each combustion-generated pollutant considered
- Evaluates the overall effect of each combustion modification on the level and speciation of each pollutant by summing individual combustion condition contributions
- Identifies combustion control/pollutant pairs in which the emission level is likely to increase with use of NO_x control

This preliminary screening represents informed speculation based on what is known about how combustion NO_x controls act, and how combustion-generated pollutants are formed. The primary purpose is to screen the matrix of control/pollutant pairs for expected adverse emission effects. Thus, some guidance for future E/A study can be formulated even in the absence of supporting data.

6.1.1 Boilers

The commonly suggested near-term combustion modification NO_x controls for boilers were summarized in Section 4.2. Applying any one of these modifications will impose some number of altered combustion conditions from the set summarized in Table 6-1. Table 6-1 also lists the postulated effects each resulting combustion condition will have on incremental emissions of carbon monoxide, vapor phase hydrocarbon, sulfate, particulates, other organic compounds, and trace metals.

In this discussion, vapor phase hydrocarbon (HC) emissions are defined as primary emissions of aliphatic, oxygenated, and low molecular weight aromatic organic compounds which exist in the vapor phase at flue gas temperatures. Organic emissions are defined as primary emissions of higher molecular weight aromatic compounds which exist largely as a condensed (liquid or solid) phase at flue gas temperatures. Thus, organic emissions will largely consist of polycyclic organic matter (POM) or polycyclic aromatic hydrocarbons (PAH), including polychlorinated and polybrominated biphenyls (PCB and PBB) if they exist. Vapor phase hydrocarbons include virtually all other emitted organic compounds including alkanes, alkenes, aldehydes, carboxylic acids, and substituted benzenes (e.g.,

TABLE 6-1. POSTULATED EFFECT OF COMBUSTION CONDITIONS ON FLUE GAS EMISSIONS FROM BOILERS

Combustion Condition	CO	Vapor Phase HC	Sulfate	Organics
Reduced local O_2 concentration	Increased	Increased	Decreased	Possibly increased because of poorer combustion efficiency and increased carbonaceous particle formation
Reduced peak flame temperature	No effect	No effect	Possibly decreased because of decreased catalyst metal volatilization and subsequent internal condensation (despite SO_3 being favored at low temperatures)	Possibly increased because of less pyrolysis and subsequent oxidation
Increased convection zone temperatures	No effect	No effect	Possibly increased because of increased convection zone catalyst deposition	Probably no effect
Decreased gas velocity	No effect	No effect	Increased because of increased convection zone catalyst deposition	Decreased because of decreased particle emissions
Increased gas velocity	No effect	No effect	Decreased because of less catalyst condensation and deposition in boiler	Increased because of increased particle emissions
Increased residence time	Possibly decreased	Possibly decreased	Possibly increased because of greater chance for reaction	Possibly decreased because of greater chance for carbon burnout
Decreased residence time	Possibly increased	Possibly increased	Possibly decreased	Possibly increased
Delayed fuel-air mixing; off-stoichiometric combustion	Possibly increased	Possibly increased	Possibly decreased because of less potential for SO_2 oxidation	Possibly increased because of greater carbonaceous particle formation
More turbulent flame	Probably no effect	Possibly decreased	Possibly increased because of more intimate SO_2, O_2, catalyst particle contact	Possibly decreased because of less soot particle formation
Increased local H_2O concentration	No effect	No effect	Possibly increased	Possibly decreased because of decreased particle emissions
Increased local NH_3 concentration	No effect	No effect	Possibly increased through near plume solution catalysis	Possibly decreased because of decreased particle emissions

(Continued on page 6-5)

TABLE 6-1. Continued

Combustion Condition	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegregating
Reduced local O_2 concentration	Possible trend to larger sizes because of less carbon burnout	Unknown effect: possibly increased soot emissions because of greater unburned carbon particles. Possibly reduced because of increased bottom ash and hopper fallout, and greater particle control efficiency for larger particles.	Possibly increased because metals remain vaporized (don't form less volatile oxides) longer, resulting in greater concentration in smaller particles	Possibly reduced because of reduced overall particle emissions (larger particles formed)
Reduced peak flame temperature	Probably no effect	Possibly increased because of reduced slagging and bottom ash fallout	Possibly reduced with particle controls because of decreased volatilization and redistribution to small particles	Possibly increased because of reduced bottom ash fallout
Increased convection zone temperatures	Probably no effect	Possibly reduced because of increased convection zone fouling	Possibly increased because metals remain vaporized longer and can segregate to small particles	Possibly reduced because of increased convection zone fouling
Decreased gas velocity	No effect	Decreased under normal operation because of greater particle deposition and hopper ash fallout	Decreased because of increased convection zone deposition	Decreased because of increased convection zone deposition
Increased gas velocity	No effect	Increased because of less convection zone particle deposition and hopper ash fallout	Increased because of increased particle emissions	Increased because of increased particle emissions
Increased residence time	Possible trend to smaller particles because of potentially increased carbon burnout	Possibly decreased because of potentially increased carbon burnout	Probably no effect	Probably no effect
Decreased residence time	Possible trend to larger particles	Possibly increased because of potentially decreased carbon burnout	Probably no effect	Probably no effect

(Continued on page 6-6)

TABLE 6-1. Concluded

T-168

Combustion Condition	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegrating
Delayed fuel-air mixing; off-stoichiometric combustion	Trend to larger particles	Possibly increased because of greater soot formation	Possibly decreased because of overall trend to larger particles, more easily controlled	Possibly decreased because larger particles more easily controlled
More turbulent flame	Trend to smaller particles	Possibly decreased because of decreased soot formation	Possibly increased because of overall trend to smaller particles	Possibly increased because of overall trend to smaller particles
Increased local H_2O concentration	Probably no effect	Possibly decreased with ESPs because of resistivity conditioning	Possibly decreased because of decreased particle emissions	Possibly decreased due to lowered particle emissions
Increased local NH_3 concentration	Trend to smaller particles (NH_4HSO_4 aerosol)	Possibly decreased with ESPs because of NH_3 (NH_4HSO_4) conditioning effects	Unknown effect: greater proportion of small particles, but better ESP efficiency possible	Possible decreased due to lowered particle emissions

benzene, toluene, xylene, ethylbenzene, etc.). This breakdown corresponds to that adopted in References 6-1 and 6-2.

Sulfate emissions are addressed in Table 6-1 instead of simple SO_x emissions because acid sulfate aerosol emissions are far more sensitive to combustion conditions. About 98 percent of the original fuel-bound sulfur introduced into a boiler typically appears in the flue gas (Reference 6-3) in some form. Combustion conditions are expected to have little effect on total SO_x (SO_2, SO_3, H_2SO_4 and metal sulfates) emissions. However, effects on the $SO_4^=/SO_2$ ratio and the speciation of sulfate between H_2SO_4 and condensed metal sulfates can be quite significant.

In Table 6-1 comments on particulates address these emissions as a single pollutant class. Effects on particle composition are considered as effects on sulfate, trace metal, and organic emissions. Particulate comments are further subdivided into expected particle size distribution effects and particulate mass emissions effects. This is done for several reasons. First, emitted size distribution has a significant bearing on eventual adverse pollutant effects. Fine particulate presents greater adverse health effects than coarse particulate because fine particles most easily penetrate the body's pulmonary defenses, and remain in the lungs for longer times. Furthermore, fine particulate remains suspended in the air for longer times. Secondly, combustion-produced particle size distribution has great impact on the actual particle load emitted from boilers with particulate controls. Fine particulate is less easily caught by these controls. Particle size distribution also significantly affects the level of trace metal emissions in these boilers. As discussed in Section 6.2.4, certain trace elements tend to concentrate in the small particles emitted from a boiler. Thus, modifications which shift the emitted particle size distribution to smaller sizes would tend to increase the emissions of this group of trace metals. Finally, as discussed in Section 6.2.5, particle size distribution can have significant effects on SO_2 to SO_3, and ultimately sulfate, conversion.

For analogous reasons, trace metal emissions are discussed in two subsets in the table: segregating trace metals and nonsegregating trace metals. Segregating trace elements are those which tend to concentrate in fine particulate. Nonsegregating trace elements are those that remain essentially evenly distributed (on a fractional mass basis) in particles of all sizes. The emissions characteristics of each group are quite different. Nonsegregating trace metal emissions are largely determined by total particulate mass emissions. Conversely, segregating trace metal emissions are significantly affected by emitted particle size distribution and boiler temperature-time profile.

The entries in Table 6-1 largely refer to a coal-fired utility boiler with a cold side electrostatic precipitator particulate control. This type of boiler represents the most general equipment class for present considerations. It exhibits all the emissions listed in the table, and illustrates the type of effects which can occur with changes in produced particle size distribution. As a result, not all entries in the table refer to all boilers. For example, natural gas-fired boilers essentially emit only CO and small quantities of HC. Thus, all entries under trace metal, organics, particulate, and sulfate do not strictly apply to gas-fired boilers. Similarly certain comments under particulate, organics, and trace metal headings do not strictly apply to oil- or coal-fired boilers without particulate controls. For example, many comments are based on the assumption that modifications which tend to produce smaller particles would tend to increase particulate mass emissions; this is because particulate controls are less efficient at collecting fine particulate. Organic (particulate POM), and segregating trace metal emissions would show corresponding increases in these instances. However, on boilers without particulate controls, a shift in particle size distribution, at constant mass production, would yield no change in emissions of particulate, organics, or trace metals. Still, with suitable interpretation, the table comments essentially describe what is expected to occur in any boiler, when the appropriate combustion condition is imposed.

As indicated in Table 6-1, CO and vapor phase hydrocarbon emissions are expected to be influenced only by excess boiler O_2 concentrations. Changes in furnace residence times or flame zone mixing may also elicit slight changes in these emissions, though these are not expected to be significant.

Sulfate emissions are influenced by local O_2 concentrations, and by the presence of metal oxidation catalysts such as vanadium and its oxides. Thus, changes in the temperature-time profile in a boiler influence catalyst metal volatilization, oxidation, and condensation, and thereby influence SO_2 to SO_3 conversion. For example, reducing peak flame temperature would cause less trace metal volatilization. Subsequently less metal vapor would be available to condense on gas stream fine particle surfaces. Consequently the availability of oxidation catalyst is limited, and less sulfate production is expected. Conversely lowered furnace gas velocities would allow increased amounts of internal particulate deposition, and thus increased levels of SO_3 production.

Particle size distribution is probably affected largely by the degree of combustion completeness, and the degree of flame zone mixing. Incomplete combustion or mixing can yield large particles with high carbon content. Particulate mass emissions will be affected by: the degree of combustion completeness (level of carbonaceous soot formation); the produced particle size distribution (large particles tend to fall out as bottom ash and are more easily collected in particulate control devices); and the temperature profile in the boiler as it affects ash slagging. Special circumstances exist in boilers equipped with ESPs. In these, increased flue gas water vapor, sulfate, or ammonia (or more appropriately ammonium bisulfate, Reference 6-4) concentrations can act to condition the flyash, thereby increasing ESP collection efficiency, and decreasing net particulate emissions.

Organic emissions, as we have defined them here (chiefly POM), are mainly influenced by the level of particulate emissions and the carbon content of the particulate. Thus, conditions which inhibit complete combustion, and conditions which increase particulate load will increase condensible organic emissions.

Nonsegregating trace metal emission levels are essentially functions of total particulate mass emissions. Segregating trace metal emissions, however, are influenced by the particle size distribution, the boiler temperature-time profile, and local O_2 concentrations. Lowered peak temperatures will decrease the extent of initial metal volatization, so particle size redistribution effects are less pronounced. Increased convection zone temperatures, however, allow volatile metals to remain in the vapor phase for longer times. Thus, when nucleation/condensation eventually occurs, condensation nuclei have less time to grow, and particle size redistribution effects are more pronounced. Low local O_2 levels also inhibit metal oxide formation. Since metal oxides are, in general, less volatile than the base metal, low O_2 levels extend the time the metals exist as vapors. Again, particle size redistribution effects will become more pronounced.

Table 6-1, as discussed above, outlined the postulated effects of individual, isolated combustion conditions on the level of flue gas emissions. Table 6-2 summarizes the postulated overall effects of implementing combustion modification NO_x controls, each of which, as shown, can effect several combustion condition changes. Table 6-2 reflects the cumulative effects of each altered combustion condition appropriate to a given combustion control technique.

Table 6-2 shows that:

- Increased CO and vapor phase hydrocarbon emissions are of major concern only when excess air levels are lowered
- Sulfate emission levels are expected to decrease or remain unchanged with all controls except combustion staging and ammonia injection

TABLE 6-2. POSTULATED OVERALL EFFECT OF COMBUSTION NO_x CONTROLS ON FLUE GAS EMISSIONS FROM BOILERS

Combustion Modification	Resulting Combustion Conditions	CO	Vapor Phase HC	Sulfate	Organics
Low excess air	Reduced local O_2 concentration; decreased gas velocities; increased furnace residence time	Increased	Increased	Decreased overall because of lowered O_2 availability	Possibly increased
Staged combustion	Reduced local O_2 concentration; reduced peak flame temperature; increased convection zone temperature; delayed flame zone mixing	Possibly increased	Possibly increased	Possibly decreased because of decreased convection zone catalysis (less volatile metal redistribution)	Possibly increased
Flue gas recirculation	Reduced local O_2 concentration; reduced peak flame temperature; reduced furnace residence time; increased gas velocities; more turbulent flame; increased convective zone temperature	Possibly increased	Possibly increased	Possibly decreased	Possibly increased
Reduced air preheat	Reduced peak flame temperature; decreased gas velocities; increased furnace residence times; increased local O_2 concentration	No effect	No effect	Possibly decreased	Possibly increased
Reduced load	Reduced flame temperature; decreased gas velocities; decreased furnace residence times; increased local O_2 concentration	Decreased	Decreased	Unknown effect: Less catalyst volatilization; but greater local O_2 concentrations	Possibly decreased
Water injection	Reduced peak flame temperature; increased local H_2O concentration	No effect	No effect	Possibly decreased	Possibly increased
Ammonia injection	Increased local NH_3 concentration	No effect	No effect	Possibly increased through near plume solution catalysis	Decreased with decreased particle emissions; no effect otherwise

TABLE 6-2. Concluded

Combustion Modification	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegregating
Low excess air	Possible trend to larger sizes	Possibly decreased because of increased bottom and ash fallout and internal deposition	Unknown effect: possible increase due to increased volatility but possible decrease with internal deposition	Possibly reduced because of reduced mineral particle emissions and internal particle deposition
Staged combustion	Possible trend to larger sizes	Unknown effect: possible increase due to soot formation; possible decrease due to larger particles and convection zone depositon and slagging	Possibly decreased because of decreased repartitioning to small particles	Possibly reduced due to larger particles (more carbon) and convection zone slagging
Flue gas recirculation	Probably no effect	Possibly increased due to increased velocities and possibility of soot formation	Possibly decreased because of decreased repartitioning to small particles	Possibly increased with increased particle emissions
Reduced air preheat	Probably no effect	Possibly increased due to less bottom slagging	Possibly reduced because of less concentration in small particles	Possibly increased with increased particle emissions
Reduced load	Probably no effect	Probably no net effect	Possibly reduced because of less concentration in small particles	Probably no effect
Water injection	Probably no effect	Possibly decreased with ESPs because of conditioning; possibly increased otherwise	Possibly reduced because of less small particle concentration and lowered particle emissions	Possibly decreased with ESPs, possibly increased otherwise; follows particulate load
Ammonia injection	Trend to smaller particles (NH_4HSO_4 aerosol)	Possibly decreased with ESPs because of conditioning; increased otherwise	Possibly increased because larger fraction of small particles	Decreased with decreased particle emissions; no effect otherwise

- Changes in emitted particle size distribution are expected only when imposing staged combustion or lowered excess air modifications. In these instances the production of larger particles is expected
- Increased particulate mass emissions are of potential concern when flue gas recirculation is used
- Condensible organic emissions are likely to increase with all combustion NO_x controls except ammonia injection
- Increased segregating trace metal emissions are possible when using staged combustion, flue gas recirculation, and ammonia injection
- Nonsegregating trace metal emissions are only of potential concern when implementing flue gas recirculation and reduced air preheat

6.1.2 Reciprocating IC Engines and Gas Turbines

The commonly considered combustion modifications for NO_x control applicable to stationary IC engines and gas turbines were summarized in Section 4.2. The set of combustion conditions resulting from imposing these modifications, and the postulated effects of each altered combustion condition on the pollutants under consideration are listed in Table 6-3. The pollutant classes tabulated in Table 6-3 are the same as those considered above for boilers. However, since IC engines and gas turbines burn natural gas or petroleum distillates (kerosene or diesel fuel) almost exclusively, some of these pollutants are currently of minor importance. For example, trace metal emissions would be of concern only for residual oil-fired gas turbines, or when fuel additives are used with distillate oils.

In Table 6-3 the postulated effects of combustion condition on incremental air emissions from stationary IC engines and gas turbines are similar to those discussed above for boilers. Exceptions here stem from the absence of particulate control devices on IC engine and gas turbine exhaust streams. In these exhaust streams particulate mass emissions and condensible organic emissions are determined solely by the degree of combustion completeness. Particle size distribution effects in the absence of particulate controls, do not influence these emissions. Similarly, emissions of nonsegregating (i.e., nonvolatilizing) trace metals are not affected by all combustion conditions; essentially everything introduced with the fuel leaves in the exhaust. Emissions of segregating trace metals are affected only by the combustion gas temperature-time profile, and by local O_2 concentrations. These affect the amount of trace metal (and which elements) that volatilize, and where condensation or deposition occurs. Thus, because reduced peak temperatures cause a lesser degree

TABLE 6-3. POSTULATED EFFECTS OF COMBUSTION CONDITIONS ON EMISSIONS FROM IC ENGINES AND GAS TURBINES

T-170

Combustion Condition	CO	HC	Sulfate	Organics
Reduced peak temperature	Possibly increased	Possibly increased	Unknown effect; potentially increased because SO_3 favored at lower temperatures; potentially decreased because of decreased trace metal volatilization and deposition	Possibly increased
Reduced residence time at temperature	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Possibly decreased because of decreased trace metal volatilization and subsequent deposition	Possibly increased due to incomplete combustion
Reduced local O_2 concentration	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Decreased	Possibly increased due to incomplete combustion
Increased local O_2 concentration	Reduced	Reduced	Increased	Possibly reduced .
Increased local H_2O concentration	No effect	No effect	Possibly increased	No effect

(Continued on page 6-14)

TABLE 6-3. Concluded

Combustion Condition	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegrating
Reduced peak temperature	Probably no effect	Possibly increased	Possibly slightly increased due to decreased volatilization and internal deposition	No effect
Reduced residence time at temperature	Trend to larger sizes due to incomplete vaporization and combustion of fuel droplets	Possibly increased due to incomplete combustion	Possible slight increase due to decreased volatilization and subsequent internal deposition	No effect
Reduced local O_2 concentration	Trend to larger sizes due to incomplete combustion of fuel droplets	Possibly increased due to incomplete combustion	Possible slight increase due to decreased formation of less volatile metal oxides, resulting in less internal deposition	No effect
Increased local O_2 concentration	Trend to smaller sizes	Possibly reduced	Possible slight decrease due to increased oxide formation and subsequent internal deposition	No effect
Increased local H_2O concentration	Probably no effect	Probably no effect	No effect	No effect

of segregating metal volatilization and subsequent deposition on internal chamber surfaces, there will be a slight increase in emissions. Similarly lowered local O_2 concentrations allow a lesser degree of metal oxidation, thereby reducing nonvolatile metal oxide deposition, and slightly increasing exhaust emissions.

Table 6-4 summarizes each NO_x control considered, and its postulated overall effect on the incremental emissions from IC engines. Table 6-5 is the analogous summary for gas turbines.

6.1.3 Warm Air Furnaces

Over 90 percent of residential and commercial warm air furnaces fire either natural gas or distillate oil. Emissions of sulfates and trace metals from these units are thus of minor concern compared to coal-fired boilers. About 3 percent of U.S. warm air furnaces still fire coal. For these, sulfates, trace metals and especially POMs could cause severe localized environmental problems. It is doubtful that NO_x controls, except for fuel switching, will be developed and implemented for these sources, however, and they will not be considered further here.

An additional factor in evaluating incremental emissions from warm air furnaces is the cyclic nature of operation. Warm air furnaces typically undergo 2 to 5 on/off cycles per hour. Studies of emissions without NO_x controls show that the starting and stopping transients have a strong, sometimes dominant, effect on total emissions of CO, HC and particulate (smoke) (References 6-5, 6-6). The effect of NO_x controls on transient emissions is presently unknown. Incremental steady state emissions must eventually be weighed against the transient emissions however, for this significance to be shown.

The range of combustion process modifications effective for NO_x control in warm air furnaces is more limited than was the case for the larger equipment types discussed above. This is due both to the combustion design constraints specific to this application and to the low unit capital and operating costs which make extensive modification unattractive. Minor process modifications, primarily burner tuning, are ineffective for NO_x control in a given unit (References 6-5, 6-6). Uncontrolled NO_x emissions among units with different burner/firebox designs differ by a factor of two or more, however (References 6-6, 6-7). Thus, the use of low NO_x burner/firebox combinations, for application to new units, is the prime candidate for NO_x control in warm air furnaces.

The combustion conditions typical of low NO_x operation in warm air furnaces are as follows:

- Lower excess air
- Reduced peak flame temperature

TABLE 6-4. POSTULATED OVERALL EFFECT OF COMBUSTION NO_x CONTROLS ON EMISSIONS FROM IC ENGINES

T-171

Combustion Modification	Resulting Combustion Condition	CO	Vapor Phase HC	Sulfate	Organics
Retard ignition	Reduced peak temperature; reduced time at temperature	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Potentially decreased due to decreased metal catalyst internal depostion	Possibly increased due to incomplete combustion
Increase air/fuel ratio	Reduced peak temperature; increased local O_2 concentration	Decreased	Decreased	Increased	Possibly decreased
Decrease air/fuel ratio	Reduced peak temperature; reduced local O_2 concentration	Possibly increased	Possibly increased	Decreased	Possibly increased due to incomplete combustion
Exhaust gas recirculation	Reduced peak temperature; reduced local O_2 concentration	Possibly increased	Possibly increased	Decreased	Possibly increased due to incomplete combustion
Decrease manifold air temperature	Reduced peak temperature	Possible increase	Possible increase	Unknown effect: possible increase because SO_3 favored at lower temperatures; possible decrease due to decreased catalytic oxidation	Possible increase
Stratified charge cylinder design	Reduced peak temperature; reduced residence time at temperature; reduced local O_2 concentration	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Potentially decreased	Possibly increased due to incomplete combustion
Derate	Reduced peak temperature	Possible increase	Possible increase	Unknown effect	Possible increase
Increase speed	Reduced residence time at temperature	Possible increase due to incomplete combustion	Possible increase due to incomplete combustion	Possible decrease due to decreased catalyst deposition	Possible increase due to incomplete combustion
Water injection	Reduced peak temperature; reduced local O_2 concentration; increased local H_2O concentration	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Potentially decreased	Possible increase due to incomplete combustion

(Continued on page 6-17)

TABLE 6-4. Concluded

T-171

Combustion Modification	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegregating
Retard ignition	Possible trend to larger sizes due to incomplete combustion	Possibly increased due to incomplete combustion	Possible slight decrease due to reduced internal deposition	No effect
Increase air/ fuel ratio	Possible trend to smaller sizes	Possibly decreased	Possible slight decrease due to reduced internal deposition	No effect
Decrease air/ fuel ratio	Possible trend to larger sizes due to incomplete combustion	Possibly increased due to incomplete combustion	Possible slight increase	No effect
Exhaust gas recirculation	Possible trend to larger sizes due to incomplete combustion	Possibly increased due to incomplete combustion	Possible slight increase	No effect
Decrease manifold air temperature	Probably no effect	Possible increase	Possible slight increase due to decreased internal deposition	No effect
Stratified change cylinder design	Possible trend to larger sizes	Possibly increased due to incomplete combustion	Possible slight increase due to decreased internal deposition	No effect
Derate	Probably no effect	Possible increase	Possible slight increase	No effect
Increase speed	Possible trend to larger sizes	Possible increase due to incomplete combustion	Possible slight increase	No effect
Water Injection	Possible trend to larger sizes	Possible increase due to incomplete combustion	Possible slight increase	No effect

TABLE 6-5. POSTULATED OVERALL EFFECT OF COMBUSTION NO_x CONTROLS ON EMISSIONS FROM GAS TURBINES

T-172

Combustion Modification	Resulting Combustion Condition	CO	Vapor Phase HC	Sulfate	Organics
Water or steam injection	Reduced peak temperature; reduced residence time at temperature; reduced local O_2 concentration; decreased local H_2O concentration	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Potentially decreased	Possibly increased due to incomplete combustion
Lean primary zone	Reduced peak temperature; increased local O_2 concentration; reduced residence time at temperature	Decreased	Decreased	Possibly increased	Possibly decreased
Early quench with secondary air	Reduced residence time at temperature	No effect	No effect	Potentially decreased	Unknown effect
Increase mass flowrate	Reduced residence time at temperature	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Possibly increased due to decreased catalyst metal internal deposition	Possible increase due to incomplete combustion
Exhaust gas recirculation	Reduced peak temperature; reduced local O_2 concentration	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Potentially decreased	Possibly increased due to incomplete combustion
Air blast or air assist atomization	Reduced peak temperature; reduced local O_2 concentration	Possibly increased due to incomplete combustion	Possibly increased due to incomplete combustion	Potentially decreased	Possibly increased due to incomplete combustion
Reduced air preheat	Reduced peak temperature	Possibly increased	Possibly increased	Unknown effect: possible increase because SO_3 favored at lower temperatures; possible decrease due to decreased internal catalyst deposition	Possibly increased
Reduced load	Reduced peak temperature; reduced local O_2 concentration	Increased	Increased	Potentially decreased	Possibly increased

(Continued on page 6-19)

TABLE 6-5. Concluded

T-172

Combustion Modification	Particulate		Trace Metals	
	Size Distribution	Mass Emissions	Segregating	Nonsegregating
Water or steam injection	Possible trend to larger sizes due to incomplete combustion	Possibly increased due to incomplete combustion	Possible slight increase due to decreased internal deposition	No effect
Lean primary zone	Possible trend to smaller sizes	Possibly decreased	Possible slight increase due to decreased internal deposition	No effect
Early quench with secondary air	Possible trend to larger sizes	Possible slight increase	Possible slight increase	No effect
Increase mass flowrate	Possible trend to larger sizes	Possible increase due to incomplete combustion	Possible slight increase due to decreased internal deposition	No effect
Exhaust gas recirculation	Possible trend to larger sizes	Possibly increased due to incomplete combustion	Possible slight increase due to decreased internal deposition	No effect
Air blast or air assist atomization	Possible trend to larger sizes	Possibly increased due to incomplete combustion	Possible slight increase	No effect
Reduced air preheat	Probably no effect	Possibly increased	Possible slight increase due to decreased internal deposition	No effect
Reduced load	Possible trend to larger sizes	Increased	Possible slight increase	No effect

- Delayed fuel air mixing and/or internal recirculation of combustion products
- Longer residence time

The general effects on combustion-generated pollutants are largely as summarized in Table 6-1 for boilers. Taken individually, the general expectation is for the modified combustion condition to increase incremental emissions. For example, Figure 6-1 shows the effect of lower excess air on CO, HC and smoke emissions (Reference 6-8). However, through careful engineering during control development, it has been possible to achieve low-NO_x combustion conditions without adverse incremental emissions (Reference 6-9). Table 6-6 shows a comparison of typical uncontrolled units and a prototype unit with an optimized burner/firebox. Incremental emissions were held constant or reduced at the low-NO_x, high-efficiency condition. Table 6-6 also shows incremental emissions with a commercially available oil emulsifier burner. Again, low-NO_x operation was achieved with no adverse effects on incremental emissions (Reference 6-10).

Data on warm air furnace POM emissions under low-NO_x operation are apparently nonexistent. Data on both transient and steady operation with and without NO_x controls are needed to form a general conclusion on the total incremental impact of NO_x controls. Additionally, it should be emphasized that the incremental emissions data shown in Table 6-6 are for well maintained laboratory operation. Data are needed on long-term field operation with NO_x controls.

6.2 EMISSIONS DATA EVALUATION

The previous subsection described the expected incremental effects of NO_x combustion controls on the emission of pollutants other than NO_x from stationary combustion sources. This subsection supports that development by presenting and discussing the available incremental emissions data obtained through several NO_x control evaluation studies. The discussion is divided into seven subsections, one for each pollutant considered in Section 6.1, plus an additional discussion of nitrate emissions. It should be noted that data on the emissions of pollutants other than CO, hydrocarbons, and particulate, as a function of NO_x control implementation, are spotty to nonexistent. Consequently in these cases a more detailed analysis of postulated pollutant formation mechanisms is presented. In light of this, an assessment of the relative need to develop the requisite information can be made.

6.2.1 Carbon Monoxide

The presence of CO in the exhaust gases of combustion systems results from incomplete fuel combustion. Several conditions existing in a combustion source can give rise to incomplete combustion. These include:

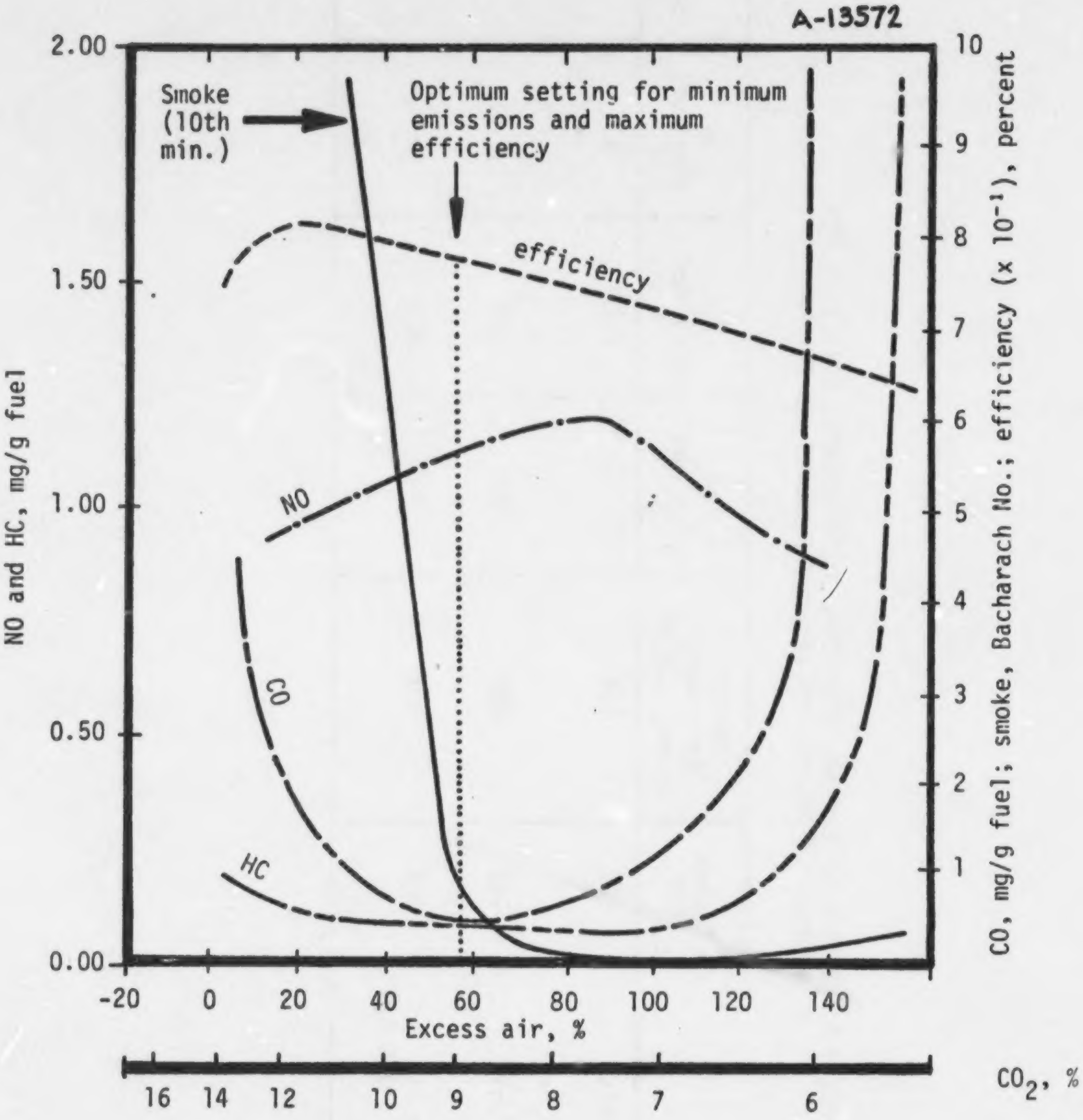


Figure 6-1. Effect of excess air on emissions from an oil-fired warm air furnace. (Reference 6-8).

TABLE 6-6. EFFECT OF LOW-NO_x OPERATION ON INCREMENTAL EMISSIONS AND SYSTEM PERFORMANCE FOR RESIDENTIAL WARM AIR FURNACES

	Excess Air	Thermal Efficiency (Steady-State)	NO g/kg fuel	CO g/kg fuel	HC g/kg fuel	Smoke Bacharach
Typical uncontrolled field units (References 6-5, 6,6)	90%	70%	1.1 - 2.7	1.05	0.1	3.2
Optimum low NO_x unit (Reference 6-9)	15%	80%	0.6	1.0	0.1	1
Water/distillate oil emulsion burner: 32% H_2O (Reference 6-10)	32%	80%	0.85	0.3	--	~1

- Insufficient O_2 availability
- Poor fuel/air mixing
- Cold wall flame impingement
- Reduced combustion temperature
- Decreased combustion gas residence time

As noted in Section 6.1, various combustion modifications for NO_x reduction can produce one or more of the above conditions. Consequently, the possibility of increased CO emissions due to combustion NO_x controls represents a justifiable concern.

Since field test programs investigating NO_x controls generally monitor combustion source CO to provide an indication of combustion efficiency, sufficient data are available to assess the effect these controls have on residual CO emissions. These data are presented and evaluated in the following subsections for utility boilers (6.2.1.1), industrial boilers (6.2.1.2), internal combustion (IC) engines (6.2.1.3), and gas turbines (6.2.1.4).

6.2.1.1 Utility Boilers

Since large quantities of CO in the flue gas of utility boilers mean decreased efficiency, these boilers are operated to keep CO emissions at a minimum. Furthermore, if flue gas CO levels reach concentrations in excess of 2,000 ppm, severe equipment damage can result because of explosions in flue gas exit passages. Thus, the degree to which a NO_x reduction technique is allowed to increase CO is limited by other than environmental concerns. In general, a NO_x control method is applied until flue gas CO reaches about 200 ppm. Further application is then curtailed.

NO_x control effects on CO emissions are highly dependent on the equipment type and the fuel fired. In utility boilers of newer design, it is generally possible to achieve good NO_x reduction without causing significant CO production. This is possible because newer burner and furnace designs allow for better combustion air control and longer combustion gas residence time. In addition, oil- and coal-fired boilers usually emit very low CO levels during low-NO_x combustion because smoke and soot production generally occur with these fuels before significant CO levels are attained. Since boiler operators strive to keep combustible losses to a minimum, conditions which result in soot formation are avoided, resulting in correspondingly low CO levels.

The combustion modifications commonly applied to utility boilers were discussed in Section 4.2. A summary of the field data on the effects of the more extensively implemented modifications on CO emissions is shown in Table 6-7. These data are discussed below for each combustion NO_x control.

TABLE 6-7. REPRESENTATIVE EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM UTILITY BOILERS (References 6-11, 6-12, 6-13)

NO_x Control	Fuel	CO Emissions (ppm)[a]	
		Baseline	NO_x Control
Low Excess Air	Natural Gas	14	68
		86	74
		12	61
		8	8
		14	34
	Oil	19	42
		85	53
		15	20
		19	19
	Coal	42	93
		20	60
		24	283
		27	81
		27	225
Off-Stoichiometric Combustion	Natural Gas	14	16
		86	67
		12	13
		14	14
	Oil	19	21
		85	85
		15	21
		28	37
	Coal	24	23
		27	26
		17	40
		31	45

[a] 3% O_2, dry basis.

TABLE 6-7. Concluded

NO_x Control	Fuel	CO Emissions (ppm)[a]	
		Baseline	NO_x Control
Flue Gas Recirculation	Natural Gas	175	65
	Oil	21	9
Load Reduction	Natural Gas	14 52 12 14	13 52 15 21
	Oil	19 30 15 19	14 5 19 22
	Coal	20 25 31 24	41 19 8 12

[a] 3% O_2, dry basis.

Low Excess Air

As the data in Table 6-7 illustrate, lower excess air levels in utility boilers can have profound effects on CO emissions. In virtually all instances, CO emissions increased significantly when excess O_2 levels were reduced 30 to 60 percent. Gas-fired boilers showed emission increases up to 400 percent when excess O_2 was lowered over this range, while oil-fired boilers were less sensitive, and showed CO emission increases from 0 to 120 percent. However, coal-fired boilers were the most sensitive to excess air reductions. Reducing excess O_2 by 40 to 60 percent gave 100 to 1,000 percent increases in CO emissions.

Off-Stoichiometric Combustion

Off-stoichiometric, or staged, combustion has proven to be a very effective NO_x reduction technique for large steam generators. As discussed in Section 4.2, it can be implemented in a variety of ways including burners out of service, overfire air ports, and biased firing. In all cases, the effectiveness of off-stoichiometric combustion (OSC) in reducing NO_x emissions depends in large part on the fraction of total combustion air that can be introduced into the second combustion stage. It is in this second stage that complete combustion of the fuel is achieved. CO emissions arise when this second stage combustion does not go to completion prior to quenching in the convective section. This is caused by a combination of the first stage being too fuel rich and the mixing of second stage air being too slow for the residence time provided. During development of retrofit or new design controls, these parameters are usually selected so that CO emissions are acceptable.

The effectiveness of OSC in reducing NO_x formation while keeping CO emissions low is highly dependent on specific equipment type. New utility boilers with multiburner furnaces are especially amenable to this technique because it is generally not difficult to adequately distribute secondary air and assure complete combustion in these sources. Consequently, implementing OSC in utility boilers is expected to elicit little effect on incremental CO emissions. This conclusion is certainly borne out by the representative data presented in Table 6-7.

Flue Gas Recirculation

The use of flue gas recirculation (FGR) for NO_x control has, in practice, been restricted to gas- and oil-fired units. Tests have shown FGR to be impractical for use in coal-fired equipment (Reference 6-14). This is so because, as discussed in Section 4.2, the technique is ineffective in reducing fuel NO_x production, the predominant source of NO_x in coal firing. When FGR is implemented, 10 to 30 percent of the total burner gas flow is recycled flue gas from the boiler exhaust. Further FGR increases can cause flame instability due to reduced flame temperatures and oxygen availability.

Theoretically, FGR can lead to increased CO emissions, but unacceptable flame instabilities usually occur before the onset of CO or smoke production. Thus, as Table 6-7 shows, the use of FGR has not caused increased CO emissions. On the contrary, CO emissions have generally decreased.

Load Reduction

Since load reduction in steam generators necessitates increased excess air levels to maintain good furnace air/fuel mixing and steam temperature control, increased CO emissions using this NO_x reduction technique are not expected. In addition, the increased combustion gas residence time afforded under reduced load would tend to facilitate complete CO burnout. As Table 6-7 illustrates, CO emissions remain relatively unchanged with reduced load.

6.2.1.2 Industrial Boilers

The bulk of the data on incremental CO emissions due to NO_x controls applied to industrial boilers was obtained in a recently completed field test program (References 6-15 and 6-16). In this study, CO emissions were reported for both baseline and for low-NO_x firing. Baseline emissions were recorded with the boiler operating at 80 percent of rated capacity under normal (or as-found) conditions. Low-NO_x testing was implemented until CO emission levels reached 100 to 200 ppm, then it was curtailed.

The data obtained during this study are summarized in Table 6-8. As indicated in the table, baseline CO emissions for industrial boilers are generally insignificant. However, the application of NO_x combustion controls in most cases adversely affected CO levels because each control was implemented until CO levels became unacceptable.

Low Excess Air

As noted for utility boilers above, CO emissions from industrial boilers are also adversely affected by excess air levels. As observed in the field study (References 6-15, 6-16), Table 6-8 illustrates that CO emissions from gas- and oil-fired boilers can be significantly increased when excess oxygen is reduced 20 to 50 percent. Coal-fired boilers showed lower incremental CO emission increases.

Off-Stoichiometric Combustion

Two methods were used in the industrial boiler study to effect OSC: overfire air and burners out of service. In these tests baseline CO emissions were always low. Combustion staging by both methods generally resulted in unchanged to slightly increased CO emissions.

TABLE 6-8. EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM INDUSTRIAL BOILERS (References 6-15, 6-16)

NO_x Control	Fuel	CO Emissions (ppm)[a]	
		Baseline	NO_x Control
Low Excess Air	Natural Gas	10	10
		0	0
		0	11
		0	900
		50	129
	Distillate Oil	47	485
		90	150
		0	17
	Residual Oil	0	45
		0	100
		0	9
		0	28
		0	205
	Coal	25	20
		70	60
		0	0
		0	22
		25	25
Off-Stoichiometric Combustion ● Overfire Air	Natural Gas	10	10
		10	20
	Distillate Oil	0	0
	Residual Oil	0	0
		0	30
		0	80
	Coal	0	49

[a] 3% O_2, dry basis.

TABLE 6-8. Concluded

NO_x Control	Fuel	CO Emissions (ppm)[a]	
		Baseline	NO_x Control
Off-Stoichiometric Combustion (Concluded) ● Burners Out of Service	Natural Gas	10	10
		0	0
		0	43
	Residual Oil	10	20
		0	0
		0	10
Flue Gas Recirculation	Natural Gas	10	0
		10	75
	Residual Oil	0	0
		0	0
Variable Air Preheat	Natural Gas	10	0
		0	30
		322	320
	Residual Oil	0	0
		0	0
	Coal	0	10
Load Reduction	Natural Gas	0	0
		0	0
		50	30
	Distillate Oil	0	0
		0	9
	Residual Oil	0	0
		0	0
	Coal	0	0

[a] 3% O_2, dry basis.

Flue Gas Recirculation

The data in Table 6-8 show that FGR has little effect on CO emissions. This conclusion substantiates what was noted in the utility boiler testing discussed previously (Section 6.2.1.1).

Variable Air Preheat

As for FGR, the data in Table 6-8 illustrate that varying combustion air temperature has almost no effect on CO emissions. This suggests that effects of peak flame temperature on CO emissions were also insignificant.

Load Reduction

During the cited industrial boiler field test program, load reduction experiments were performed with the boiler controls on automatic. Therefore, excess air levels increased when boiler load was reduced. As a consequence, CO emissions remained unchanged, or decreased slightly as load was reduced.

6.2.1.3 Internal Combustion Engines

As discussed in Section 4.2, the most common NO_x reduction techniques applied to IC engines include derating, ignition retard, altering air/fuel (A/F) ratios, reducing manifold air temperatures (MAT), and water injection. The effects of each of these NO_x controls on engine CO emission levels are summarized in Table 6-9 (Reference 6-17).

As indicated, baseline CO emissions from two-cycle engines are generally lower than those from four-cycle engines. However, derating two-cycle engines increased CO emissions 50 to 100 percent, while derating four-cycle engines actually gave a 60 to 100 percent decrease in CO levels.

Retarding ignition generally caused increased CO output for all engines. This is somewhat expected since retarding ignition decreased both peak combustion temperature and combustion gas residence time. Both increasing A/F ratios and reducing MAT had little effect on CO levels. However, decreasing A/F caused 50 to 100 percent increases in CO emissions. Water injection did not affect CO emissions from gas and dual fuel engines, but increased diesel engine CO emissions by 60 to 130 percent.

6.2.1.4 Gas Turbines

The effects of the commonly implemented NO_x control techniques on CO emissions from gas turbines are summarized in Table 6-10. From the table, it is apparent that reducing turbine load

TABLE 6-9. REPRESENTATIVE EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM IC ENGINES
(Reference 6-17)

Fuel	Engine Type	Baseline Emissions (ng/J)	NO_x Control CO Emissions (ng/J)					
			Derate	Retard Ignition	Increase A/F	Decrease A/F	Reduce MAT	Water Injection
Natural Gas	2-cycle	15 - 40	40 - 94	36 - 45	29 - 31	--	29 - 45	--
	4-cycle	75 - 3350	54 - 150	80 - 1000	--[a]	117	131	194
Diesel	2-cycle	72 - 325	89	140 - 628	--	--	71	464
	4-cycle	114 - 546	100 - 180	260 - 654	439	675	142 - 550	460 - 606
Dual Fuel	2-cycle	165	244	244 - 267	--	244	67	--
	4-cycle	200 - 670	289	679 - 1070	288	296	632	503 - 507

T-173a

[a] denotes no data reported.

TABLE 6-10. REPRESENTATIVE EFFECTS OF NO_x CONTROLS ON CO EMISSIONS FROM GAS TURBINES (Reference 6-18)

NO_x Control	Fuel	CO Emissions (ppm)[a]	
		Baseline	NO_x Control
Load Reduction	Natural Gas	21	357
		102	708
	Kerosene	981	1359
		90	285
	Diesel	63	441
		53	744
		162	900
Lean Primary Zone	Natural Gas	102	51
	Kerosene	102	96
	Diesel	53	99
		195	59
Air Blast/ Piloted Air Blast	Kerosene	969	110
	Diesel	53	36
Water Injection	Natural Gas	147	1134
		252	1512
	Diesel	99	144
		135	162
		93	30

[a] 3% O_2, dry basis. Baseline emissions at full load. NO_x control emissions at idle for load reduction; at full load for other NO_x controls.

causes dramatic increases in CO production. This results because gas turbines are typically designed to operate at optimum efficiency at full load. Under full load, combustion efficiencies in excess of 99 percent are common. However, combustion efficiency drops to 90 or 95 percent under idle or low power conditions, because firing temperature and fuel/air ratios are reduced at the lower load. The partially combusted gases are generated by the incoming dilution air and CO emissions increase significantly.

The other dry NO_x control techniques for gas turbines, notably leaning the primary zone and air blast (or air-assist atomization), generally reduce CO levels. The additional air introduced into the combustor when applying these techniques allows more complete fuel combustion. Thus, as shown in Table 6-10, CO emissions decrease.

Wet control techniques such as water injection tend to quench combustion and give lower combustor temperatures. This can lead to incomplete combustion and increased CO levels. Table 6-10 shows that, indeed, CO emissions increase when water injection is implemented.

6.2.1.5 Summary

In summary, except for lowering excess air levels, the available data indicate that NO_x combustion modifications have little effect on CO emissions from boilers. Low excess air causes CO emissions increases in boilers. Most NO_x controls increase CO emissions from IC engines 50 to 100 percent. In contrast, only load reduction and water injection cause CO increases in gas turbines. Dry controls actually decrease CO levels from these sources.

It is clear, therefore, that certain NO_x combustion controls can exacerbate CO emission problems from stationary combustion sources. However, this should cause only minor environmental concern. Since stationary combustion produces only about 1 percent of the total nationwide CO burden, slight increases in CO emissions due to NO_x controls in these sources should have negligible impact.

6.2.2 Hydrocarbon Emissions

Hydrocarbon (HC) emissions from combustion sources are of environmental concern because of their role in the atmospheric reactions leading to photochemical smog. The terms reactive hydrocarbons, and nonmethane hydrocarbons have been applied to this pollutant class, which includes essentially all vapor phase organic compounds emitted from a combustion source.

Stationary combustion sources are only minor contributors to ambient HC levels, accounting for only about 1 percent of the total nationwide HC emissions (Reference 6-19). Nevertheless, the possibility of increased stationary source HC emissions due to NO_x combustion controls is of definite concern. Like CO emissions, as discussed in the previous subsection, HC emissions arise in combustion source exhaust gases because of incomplete combustion. The imposition of certain NO_x combustion modification controls can result in decreased combustion efficiency and thereby increase HC levels.

Three general equipment classes are considered in the following discussion: boilers, internal combustion engines, and gas turbines.

6.2.2.1 Boilers

Field test programs studying the effectiveness of NO_x controls often monitor flue gas HC emissions as a supplementary measure of boiler efficiency. Therefore, some data on the effect of these controls on HC emissions are available.

Two recent test programs on utility boilers routinely measured flue gas HC (References 6-11, 6-12). However, in virtually all tests, both baseline and low-NO_x emissions were less than 1 ppm (or below the detection limit of the available monitoring instrument). Thus, it was concluded that HC emissions are relatively unaffected by imposing preferred NO_x combustion controls on large utility boilers.

A recent field test program investigating NO_x controls applied to industrial boilers reported more comprehensive data (References 6-15, 6-16). These data are summarized in Table 6-11, and show that the use of NO_x combustion controls generally does not affect flue gas HC levels. Some tests show a slight increase in HC emissions, yet others indicate slight reductions. Based on these data, it seems fair to conclude that HC emissions from boilers are virtually unaffected when implementing NO_x combustion controls. However, this conclusion is not altogether unexpected. The presence of unburned HC in flue gases implies poor boiler operating efficiency; NO_x controls which significantly decrease efficiency have found little acceptance.

6.2.2.2 Internal Combustion Engines

In contrast to boiler behavior, the use of NO_x combustion controls on IC engines can have significant effects on HC emissions. Different NO_x reduction techniques elicit different effects.

As shown in Figure 6-2, derating causes HC emissions to increase. This increase becomes more pronounced as load is reduced. Derating, in general, causes a 20 to 130 percent increase in HC emissions.

TABLE 6-11. REPRESENTATIVE EFFECTS OF NO_x CONTROLS ON VAPOR PHASE HYDROCARBON EMISSIONS FROM INDUSTRIAL BOILERS (References 6-15, 6-16)

NO_x Control	Fuel	HC Emissions (ppm)[a]	
		Baseline	NO_x Control
Low Excess Air	Natural Gas	42	34
		10	0
		17	13
		7	8
	Distillate Oil	3	9
	Residual Oil	8	13
		35	25
	Coal	11	18
		21	7
Load Reduction	Natural Gas	42	45
		17	18
		7	5
	Residual Oil	8	8
Off-Stoichiometric Combustion			
● Overfire Air	Natural Gas	5	0
	Distillate Oil	0	0
	Residual Oil	0	0
● Burners Out of Service	Natural Gas	0	0
	Residual Oil	12	14
		35	15
Flue Gas Recirculation	Residual Oil	0	0
Variable Air Preheat	Natural Gas	10	0
	Residual Oil	15	13
		35	25

[a] 3% O_2, dry basis.

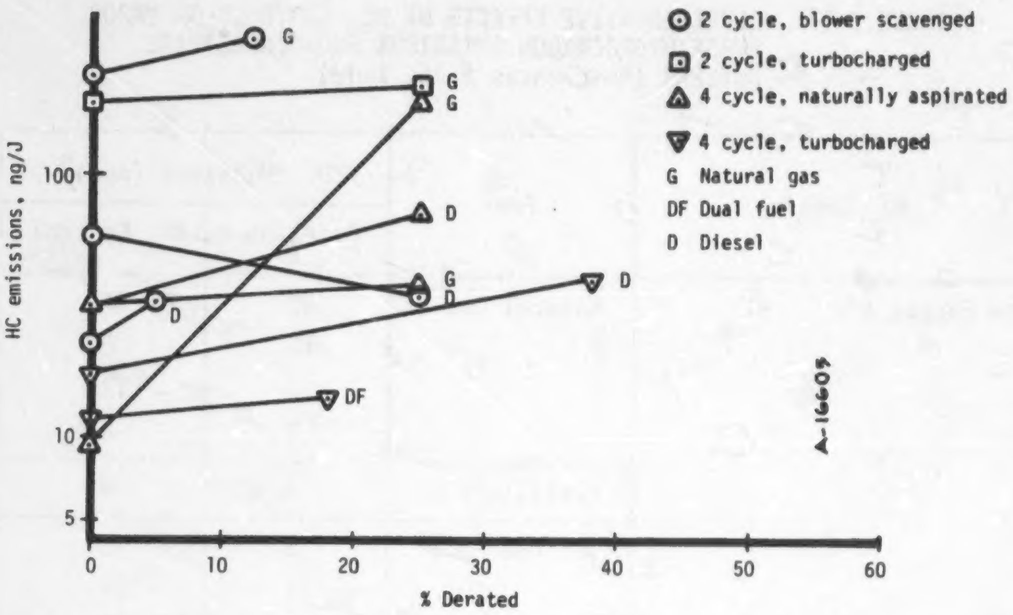


Figure 6-2. Effect of derating on IC engine HC emissions (Reference 6-17).

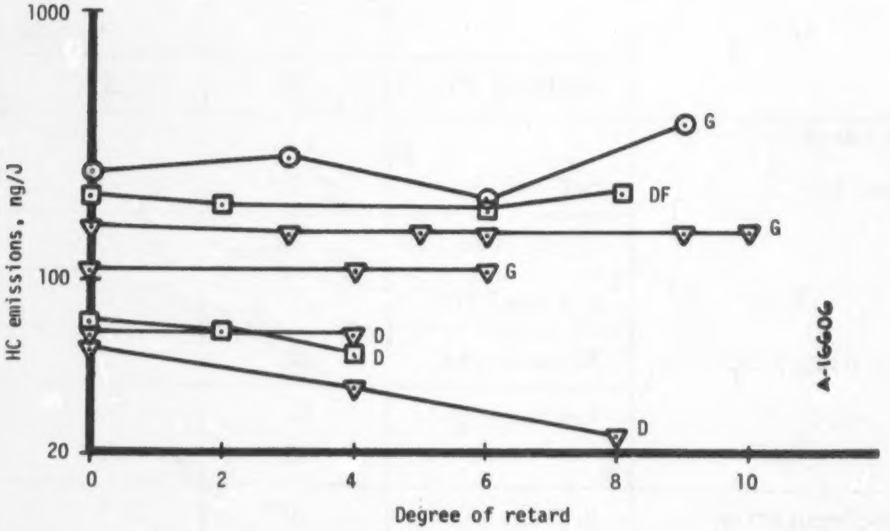


Figure 6-3. Effect of retarding ignition on IC engine HC emissions (Reference 6-17).

Figure 6-3 shows the effect of ignition retard on residual HC emissions. In contrast to the effects of engine derating, ignition retard tends to decrease slightly or not affect emissions of HC. However, in cases where retarding ignition initially reduces HC emissions, increasing the degree of ignition retard seems to have little further effect. The data in the figure indicate that HC emissions decrease on the average of 30 percent when ignition is retarded 3 to 8 degrees.

Changing the air-to-fuel (A/F) ratio, decreasing manifold air temperature (MAT) and water injection result in increased HC emissions. As shown in Figure 6-4, both increasing and decreasing the A/F ratio by 10 percent increases HC levels 20 to 65 percent. The larger percentage increases occur in engines with high baseline emissions. Figure 6-5 shows analogous effects when MAT is decreased. Decreasing MAT 10 to 20K (20 to 40F) increases HC emissions 5 to 50 percent. HC levels increase as MAT is further reduced. Turbocharged engines exhibit the largest percentage emissions increase. Water injection also increases HC emissions from IC engines regardless of the baseline HC level, as shown in Figure 6-6. Average increases of 16 to 25 percent have been experienced for water/fuel (W/F) ratios of 0.1 to 0.25.

In summary, derating, changing the A/F ratio, decreasing MAT, and water injection tend to significantly increase HC emissions from IC engines. Retarding ignition has little effect. Derating, decreasing MAT, increasing the A/F ratio, and water injection all lower combustion temperatures. Decreasing the A/F ratio reduces combustion O_2 availability. Both of these effects tend to lead to incomplete combustion, which would increase HC emissions. The unchanged or slightly decreased HC emissions with ignition retard is a somewhat unexpected result. The combustion conditions resulting from retarded ignition (decreased combustion temperatures and residence times) would be expected to give rise to increased HC levels. The reason this does not occur is unclear at this time.

6.2.2.3 Gas Turbines

Data on incremental HC emissions from NO_x combustion controls applied to stationary gas turbines are quite limited. However, sufficient data are available to allow tentative conclusions to be formed. HC emissions, like CO emissions, increase significantly with load reduction in gas turbines. As shown in Table 6-12, measured HC emissions at full load fall in the 3 to 50 ppm range. Idle firing, with attendant reduced combustion efficiency, increases these levels to the 30 to 230 ppm range.

The effects of other dry NO_x controls applied to gas turbines are mixed. As Table 6-12 shows, staged fuel injection and air assist atomization, or air blast, increase HC emissions. In contrast, leaning the primary zone tends to decrease HC levels. Increased combustion efficiency due to higher combustion temperatures tends to support this latter observation.

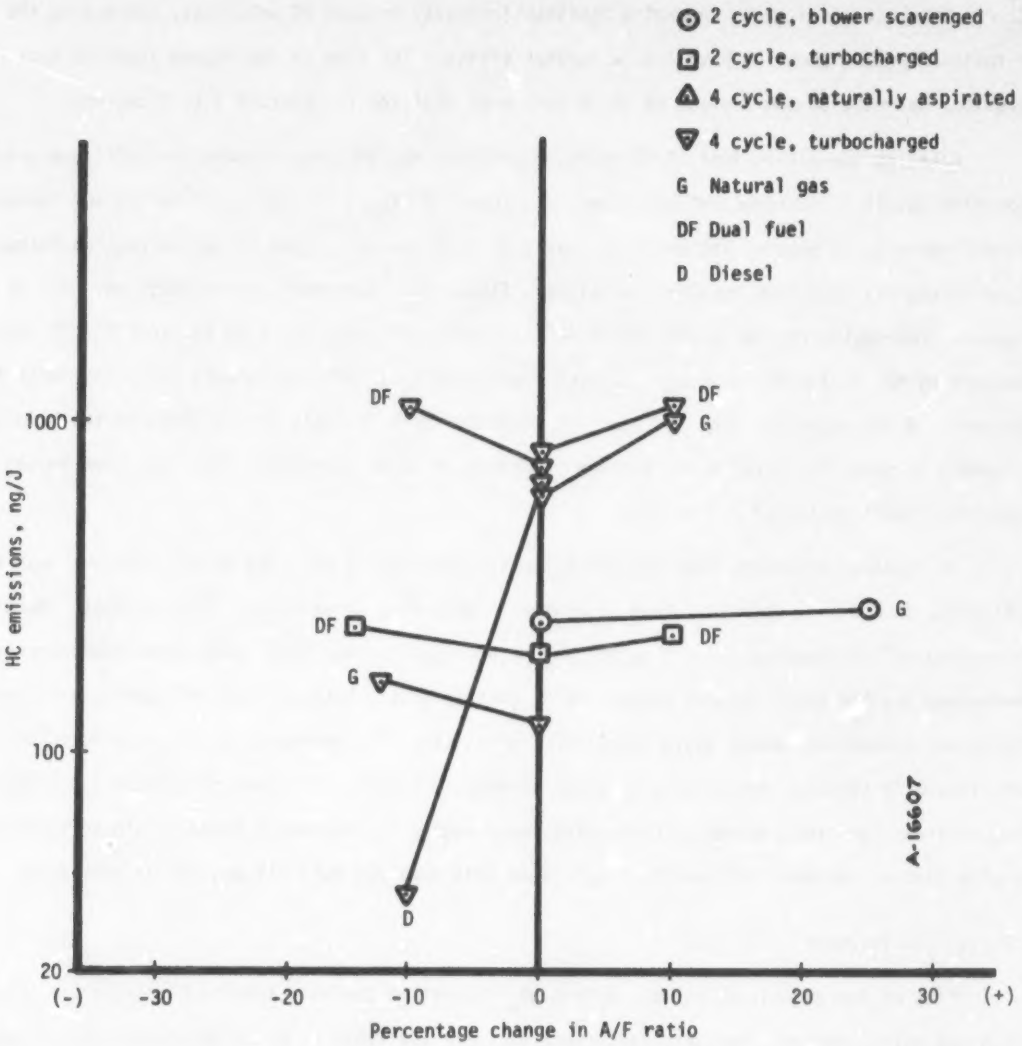


Figure 6-4. Effect of air-to-fuel ratio on IC engine HC emissions (Reference 6-17).

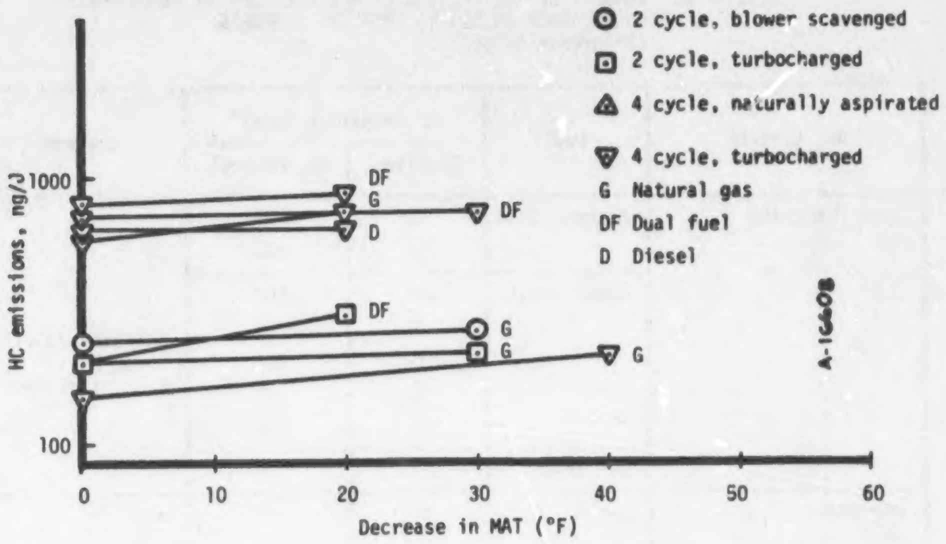


Figure 6-5. Effect of decreased manifold air temperature on IC engine HC emissions (Reference 6-17).

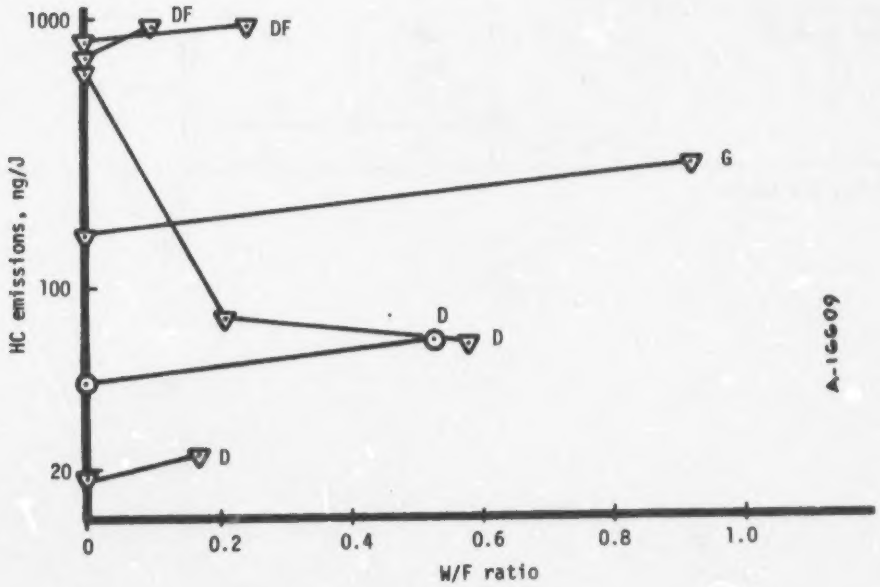


Figure 6-6. Effect of water injection on IC engine HC emissions (Reference 6-17).

TABLE 6-12. SUMMARY OF THE EFFECTS OF NO_x CONTROLS ON VAPOR PHASE HYDROCARBON EMISSIONS FROM GAS TURBINES (Reference 6-18)

T-174

NO_x Control	Fuel	HC Emissions (ppm)[a]		Comment
		Baseline	NO_x Control	
Load Reduction	Natural Gas	13	74	Baseline at full load; NO_x control at idle
		13	230	
	Diesel Fuel	53	107	
		3	30	
		36	126	
		30	93	
		18	96	
	Kerosene	27	111	
Air Blast	Jet-A	18	41	Idle
		9	11	Full load
Staged Fuel Injection	Jet-A	18	1215	Idle
		9	24	Full load
Lean Primary Zone	Natural Gas	33	9 - 12	Full load
	Diesel Fuel	30	12	
		3	7	
	Kerosene	27	12	
Water Injection	Natural Gas	234	372	W/F = 0.5
		141	246	
		36	27	
	Diesel Fuel	24	12	

[a] 3% O_2, dry basis.

The effects of applying wet NO_x controls on HC emissions are also mixed. As indicated in Table 6-12, with water injection at a water-to-fuel (W/F) weight ratio of 0.5, HC emissions increased for turbines having high baseline HC emissions, but decreased for turbines which emitted low baseline HC levels.

6.2.2.4 Summary

In summary, it can be concluded that incremental hydrocarbon emissions are of little concern when applying NO_x combustion modification controls to boilers. In these instances HC emissions are either unaffected, or actually decrease, when NO_x controls are implemented. Incremental HC emissions from stationary IC engines and gas turbines could be of some concern. However, these should have little environmental impact because the HC emissions from these equipment classes are far less than from, for example, mobile sources, and contribute minimally to the overall atmospheric burden.

6.2.3 Particulate Emissions

Although gas-fired units produce negligible amounts of particulates, oil- and coal-fired stationary sources currently emit approximately 28 percent of the nationwide particulate and smoke (Reference 6-19). Potential adverse effects on these particulate emissions from NO_x combustion controls could therefore have significant environmental impact.

The physical characteristics of particulates from oil- and coal-fired boilers can vary significantly. Particulate emissions from oil combustion can be composed of soot (condensed organic matter), cenospheres (hollow char particles), and ash (incombustible mineral matter). Coal particulate emissions are largely ash, occasionally containing some unburned carbonaceous residue. Although the distinctions between oil and coal particulate are rarely made in published data, they can be important for several reasons. For one thing, the composition of emitted particulate can have a large bearing on its size distribution. And, because most particulate controls collect large particles much more efficiently than fine particles, size is a key factor in determining how much particulate can be collected. In addition, as discussed in Section 6.2.4, emissions of certain trace metals are highly dependent on particle size distribution. Also, as discussed in Section 6.2.5, sulfate production can be significantly affected by particle size distribution and the availability of catalytic surfaces. Finally, as discussed in Section 6.2.6, polycyclic organic matter (POM) emissions from combustion sources occur largely as solid phase carbonaceous residue. Thus, the presence of high soot emissions or emissions of flyash with high carbon content would indicate the possibility of high POM emissions.

The formation of particulates in a combustion source is intimately related to combustion aerodynamics, the mechanisms of fuel/air mixing, and the effects of these factors on combustion gas temperature-time history. Of course, these are also the parameters which control NO_x formation. For example, the effects of burner swirl on NO_x production were briefly discussed in Section 4.2. However, swirl is also an important factor in determining particulate emission levels from a combustor. As Figure 6-7 illustrates, there is generally an optimum value of swirl for a given combustion system (Reference 6-20). Burner swirl can also influence emitted particle size distributions. Low swirl values tend to produce soot in the 10 to 40 μm range. Increasing swirl decreases formation of these large particles, but overswirling increases the production of submicron soot particles and reduces the extent of burnout of the largest particles.

Unfortunately the optimum conditions for reducing particulate formation (intense, high temperature flames as produced by high turbulence and rapid fuel/air mixing), are not the conditions for suppressing NO_x formation. Therefore, most attempts to produce low-NO_x combustion designs have been compromised by the need to limit formation of particulates. This compromise has generally produced designs which maintain a well controlled, cool flame, while still providing sufficient gas residence time to completely burn carbon containing particles.

The NO_x combustion controls currently receiving the most widespread application in boilers are low excess air, off-stoichiometric combustion (OSC), flue gas recirculation (for gas and oil), and load reduction or enlarged firebox. As briefly discussed in Section 6.1, the altered combustion conditions resulting from these modifications can be expected to influence emitted particulate load and size distribution.

Since smoke and particulate emissions tend to increase as available oxygen is reduced (soot emissions increase and ash particles contain more carbon), the degree to which excess air can be lowered to control NO_x is usually limited by the appearance of smoke in oil- and coal-fired units. Of course, the extent to which excess air can be limited depends on equipment type and design. Many modern burners can operate on as little as 3 to 5 percent excess air.

Similarly, the degree to which OSC can be employed is frequently limited by the degree to which the primary flame zone can be stably operated fuel rich, how well the second stage air mixes with primary stage combustion products, and the residence time for combustion in the second stage. Soot and carbon particles formed in the fuel-rich primary stage tend to resist complete combustion downstream of that stage.

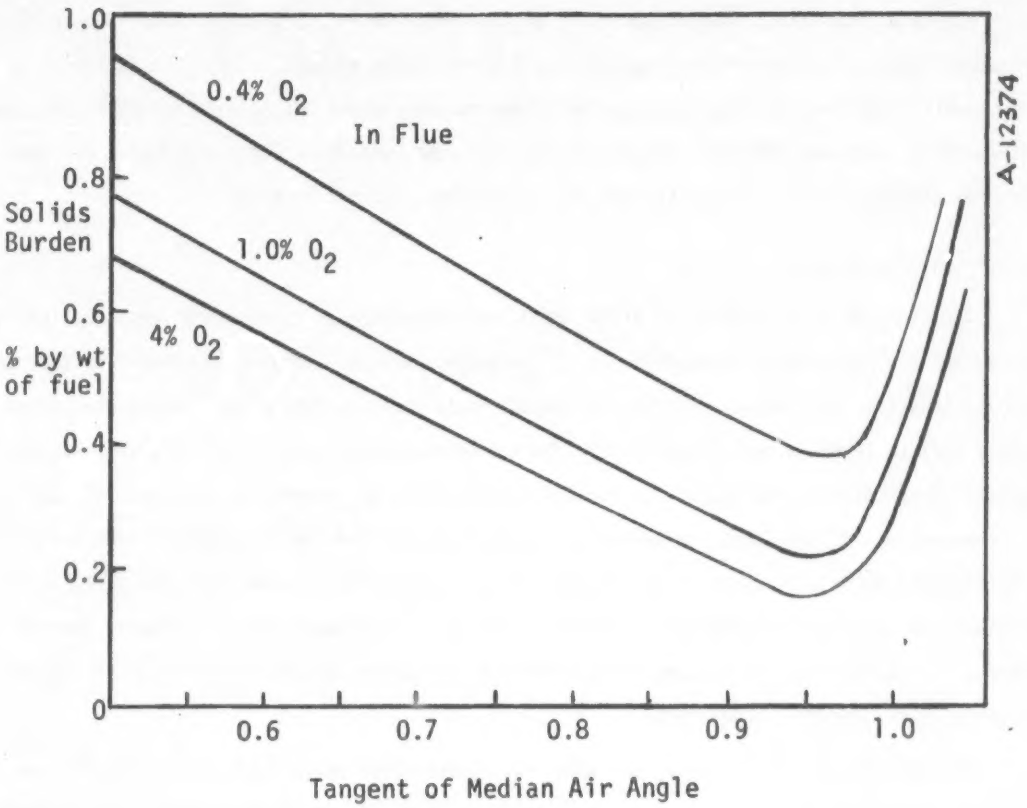


Figure 6-7. Effect of combustion air swirl on solid emissions with oil combustion (Reference 6-20).

Flue gas recirculation on oil-fired units can decrease particulate emissions by providing more intimate mixing. Kamo, et al., (Reference 6-21) have demonstrated that recirculation rates of 40 to 50 percent on a heater-sized, oil-fired furnace reduced the smoke number significantly.

Load reduction on existing units and use of enlarged fireboxes on new units cause reduced flame temperatures through lowered volumetric heat release rates. Although this could cause increased production of particulates, the longer furnace residence times accompanying reduced load offset this effect by providing more time for complete combustion.

Few data from actual field tests exist on the effect of NO_x combustion controls on particulate emissions. Even less data exist on particle size distribution effects. This is unfortunate because of the importance of size distribution in determining actual particulate emissions from sources with particle controls. However, the data which have been reported are presented and discussed below for utility boilers, industrial boilers, IC engines, and gas turbines.

6.2.3.1 Utility Boilers

Published data on the effects of NO_x reduction techniques on particulate emissions from utility boilers are scattered and insufficient for in-depth analysis. Table 6-13 summarizes the particulate emissions data obtained during two recent field test programs which studied coal-fired utility boilers (References 6-11 and 6-12). During these studies, particulate measurements were recorded under baseline and low-NO_x conditions. Since these NO_x conditions were generally produced by a combination of low excess air and staged combustion, the individual effect of each technique on particulate emissions cannot be determined. Nevertheless, the data do show that particulate emissions are relatively unaffected by "low-NO_x" firing in front wall and horizontally opposed fired boilers. Tangentially-fired boilers, on the other hand, exhibit slightly increased particulate emissions under "low-NO_x" conditions.

The effects of low-NO_x firing on carbon (or combustible) content of the particulate are also shown in Table 6-13. Although the data are quite scattered, it appears that carbon losses increase for front wall and horizontally opposed firing under low-NO_x conditions, but decrease slightly for tangential firing. However, the changes are small and may not be significant.

The effects of "low-NO_x" conditions on particle size distribution have also been investigated to a limited extent (Reference 6-11). The data from a study of particle size distribution in three boilers are summarized in Table 6-14. As the table shows, no significant changes were noted in two of the boilers, both of which were tangentially fired. In the third, a horizontally opposed boiler,

TABLE 6-13. EFFECTS OF NO_x CONTROLS ON PARTICULATE EMISSIONS FROM COAL-FIRED UTILITY BOILERS (References 6-11, 6-12)

Firing Mode	Particulate Emissions (μg/J)		% Carbon on Particulate	
	Baseline	Low NO_x	Baseline	Low NO_x
Front Wall	2.00 - 3.39	1.65 - 2.42	5.90 - 6.29	8.46 - 12.4
Horizontally Opposed	1.30 - 1.65	1.34 - 1.78	2.8 - 5.5	6.73 - 11.82
	3.29 - 3.83	2.40 - 3.60	0.53 - 0.69	0.18 - 0.46
Tangential	0.86 - 2.21	2.36 - 2.40	24.2 - 25.8	14.8 - 18.8
	1.08 - 1.84	1.23 - 2.95	0.92 - 1.98	0.8 - 1.53

TABLE 6-14. EFFECTS OF NO_x CONTROLS ON EMITTED PARTICLE SIZE DISTRIBUTION FROM COAL-FIRED UTILITY BOILERS
(Reference 6-11)

Equipment Type: Firing Mode	Firing Condition	Average Weight Percent Particles of Size:					
		>2.5 µm	2.0 µm	1.5 µm	1.0 µm	0.5 µm	<0.5 µm
Tangential	Baseline	81.78	9.12	2.01	2.64	2.92	1.55
	Low NO_x	80.74	8.91	2.28	2.92	3.25	1.88
Tangential	Baseline	92.75	2.97	0.70	0.97	1.21	1.38
	Low NO_x	93.94	1.89	0.59	0.86	1.10	1.61
Horizontally Opposed	Baseline	92.56	2.59	0.62	0.96	1.45	1.84
	Low NO_x	59.37	10.77	4.08	5.89	9.55	10.36

a distinct shift to smaller particles was noted. However, the author reported problems with the sampling and particle sizing equipment in this test, so the data may not be significant.

6.2.3.2 Industrial Boilers

The recently completed industrial boiler field test program, previously cited in Sections 6.2.1.2 and 6.2.2.1 (Reference 6-16), also collected some particulate emissions and size distribution data that show the effects of several NO_x combustion controls. These particulate emissions data from several oil- and coal-fired boilers are summarized in Figure 6-8. The figure shows changes in particulate emissions versus changes in NO_x emissions from baseline conditions as a function of the applied NO_x control.

As Figure 6-8 shows, the effects of NO_x controls on particulate emissions are mixed. For example, both forms of off-stoichiometric combustion tested increased particulate emissions by 15 to 90 percent, while flue gas recirculation increased emissions by 10 percent. In contrast, reducing boiler load and air preheat decreased particulate emissions 45 and 65 percent, respectively. Furthermore, low excess air firing generally lowered particle emissions 25 to 60 percent.

This last observation suggests that the effects of furnace gas velocity on flue gas particle emissions were quite significant in these tests. Low excess air firing decreases boiler volumetric gas flowrate, which in turn decreases combustion gas velocities. With lowered gas velocity, more particulate would be collected as bottom ash, and more ash would deposit on internal boiler surfaces. Therefore, flue gas particulate load should decrease. Figure 6-7 suggests that this phenomenon is important and offsets the effects of decreased combustion completeness expected with lowered excess air levels.

The above observations are in general agreement with those of Heap, et al., (Reference 6-22) who studied FGR and staged combustion applied to two oil-fired packaged boilers. They found that smoke emissions increased slightly when both FGR and staged combustion were applied.

Cato, et al., (Reference 6-16) also reported some very limited particle size distribution data, shown in Figure 6-9. This figure shows that, in a distillate oil-fired boiler, as excess air levels are lowered, the emitted particle size distribution shifts slightly to larger sizes. A more pronounced shift to larger particle sizes was observed with reduced load in a residual oil-fired boiler. However, these data are much too limited to allow any definite conclusions to be made regarding the effects of combustion modifications on flue gas particle size distribution.

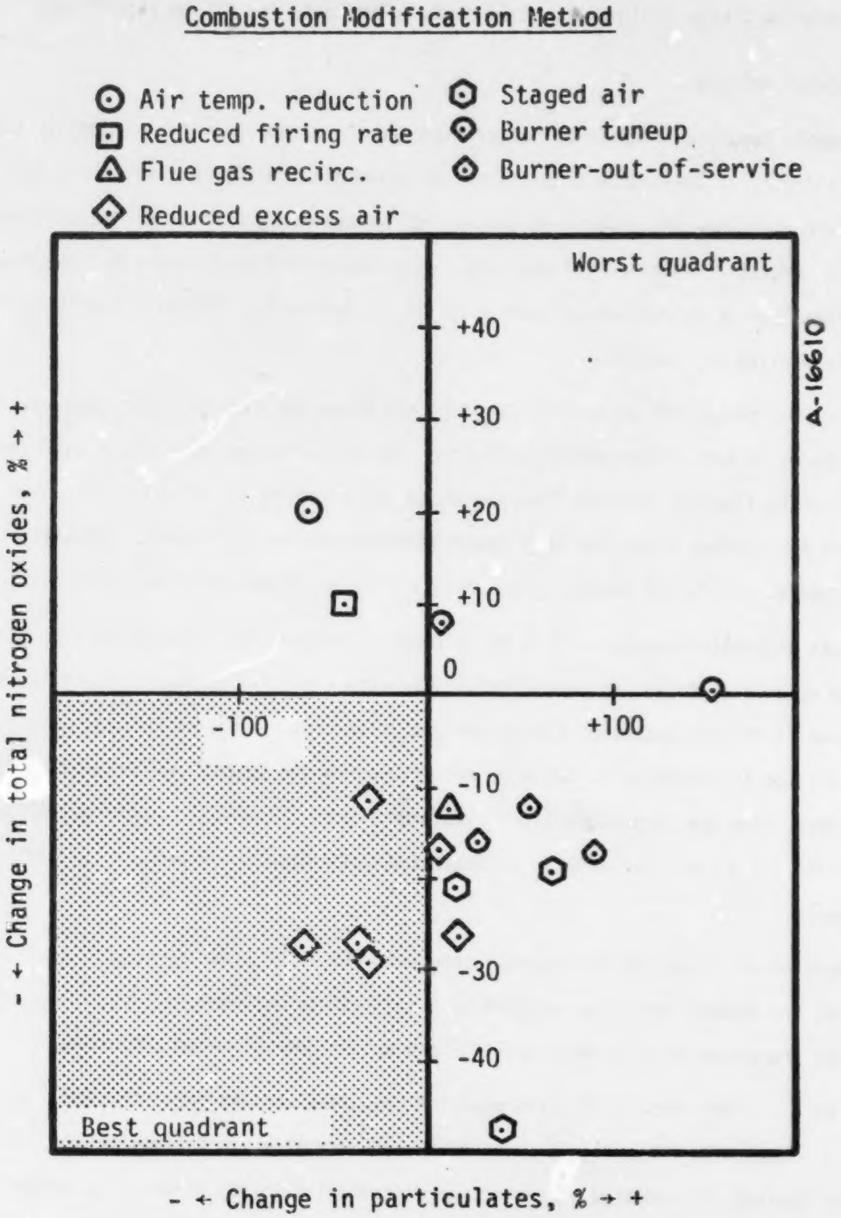


Figure 6-8. Effect of NO_x controls on solid particulate emissions from industrial boilers (Reference 6-16).

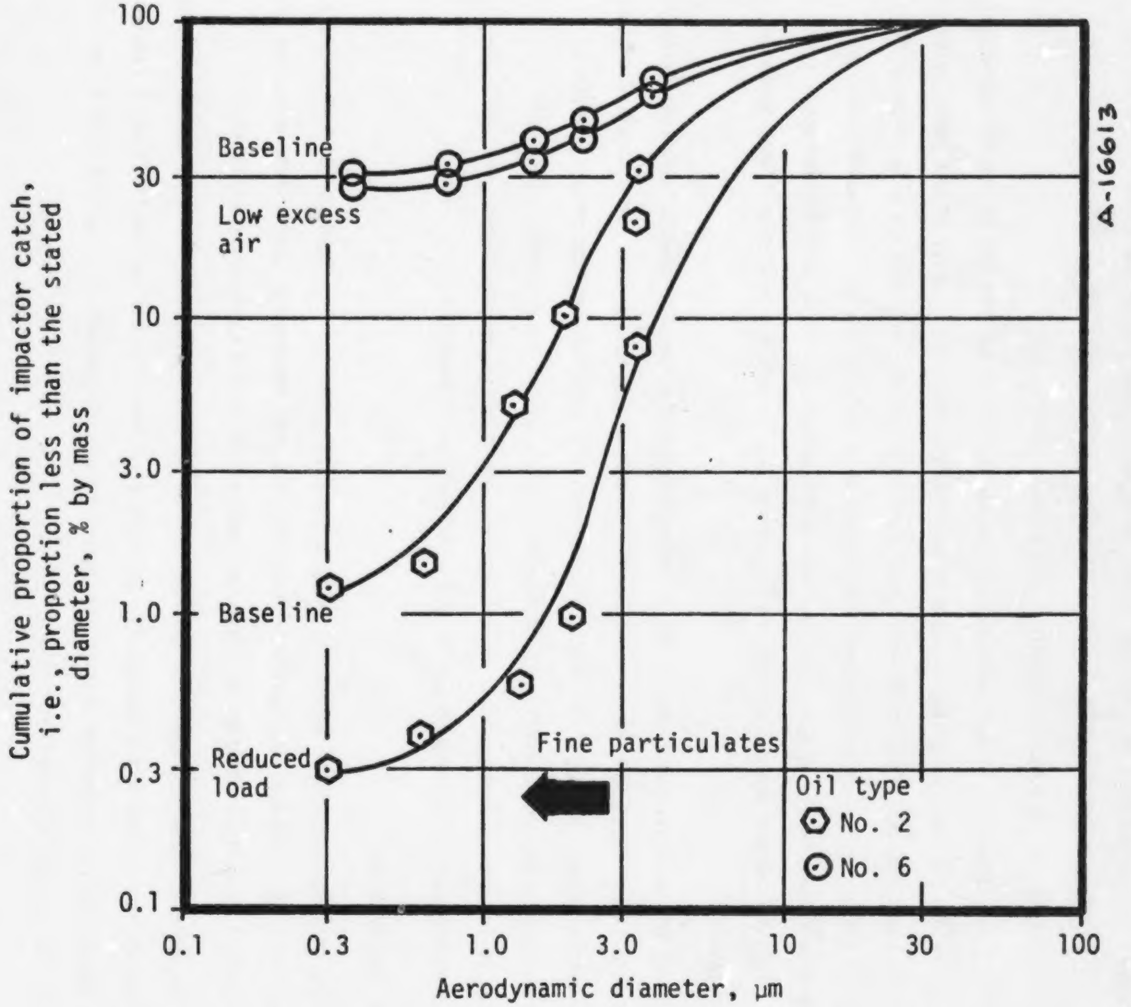


Figure 6-9. Effects of NO_x controls on particulate size distribution from oil-fired industrial boilers (Reference 6-16).

6.2.3.3 Internal Combustion Engines

Because it is quite difficult, time consuming, and expensive to measure particulate emissions from IC engines directly, virtually no data are available on particulate emission rates from this equipment class. Instead, exhaust gas opacity readings have been used as a measure of the particulate emissions. These readings effectively measure the particulate since a relationship between visible smoke and particulate mass emissions has been established for medium power diesel engines (References 6-23 and 6-24). Therefore, IC engine smoke emissions are generally reported as percent plume opacity, or as Bosch or Bacharach smoke spot numbers.

The plumes from most larger bore engines are nearly invisible when the engine is operating at steady-state. However, applying NO_x combustion controls can significantly affect smoke emissions. Figure 6-10 shows the relationship between smoke emissions and NO_x reduction as a function of NO_x control for those engines where data were reported on both pollutants. As the figure shows, NO_x controls (other than derating) generally increase smoke emissions, while derating decreases smoke levels. Ignition retard and exhaust gas recirculation (EGR) cause the most significant increases in smoke level.

Since NO_x controls which caused smoke levels to exceed 10 percent opacity were considered unacceptable in the tests summarized in Figure 6-10, none of the data points for controlled engines are above this value. However, the effect of progressively applying ignition retard and EGR on smoke emissions is best demonstrated by data which include higher smoke levels. Such data are presented in Table 6-15 for two-cycle diesel engines, and clearly show that smoke emissions increase progressively as percentage EGR or degree of retard is increased.

6.2.3.4 Gas Turbines

The data on particulate emissions from gas turbines resulting from applied NO_x controls are also very limited. However, the available data indicate that incremental particulate emissions from NO_x controls follow trends similar to those for incremental CO and hydrocarbon emissions.

Figure 6-11 shows the effect of turbine load on particle emissions. Like CO and HC emissions (as discussed in Sections 6.2.1 and 6.2.2), particle emissions increase as turbine load is reduced. As the figure shows, particulate emission increases average 40 percent when turbine load is decreased to 30 percent of rated capacity.

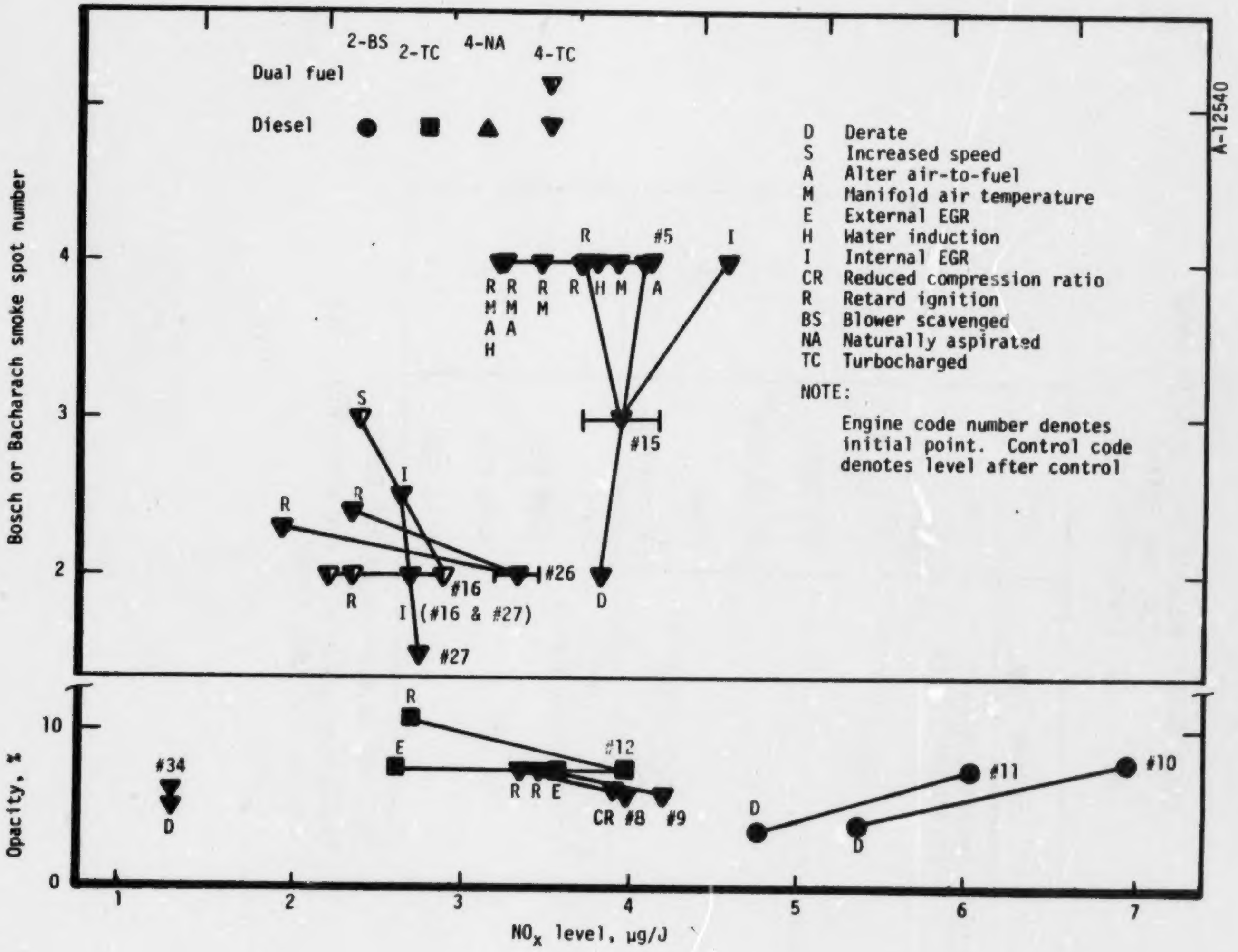


Figure 6-10. Smoke levels versus NO_x levels for large bore diesel engines (Reference 6-17).

TABLE 6-15. RELATIONSHIP BETWEEN SMOKE, EGR, AND RETARD (Reference 6-17)

Engine Type	Control[a]	Opacity, %
2-cycle, Blower Scavenged Diesel	None	4.7
	10% EGR	12
	20% EGR	27.5
	39% EGR	59
	4° advance[b]	2.7
	None	4.6
	4° retard	10
2-cycle, Turbocharged Diesel	None	7.5
	4.9% EGR	10.0
	8.4% EGR	11.5
	12.1% EGR	14.8

[a] All EGR data based on hot EGR.

[b] Injection advance is not a control; data included to show trend.

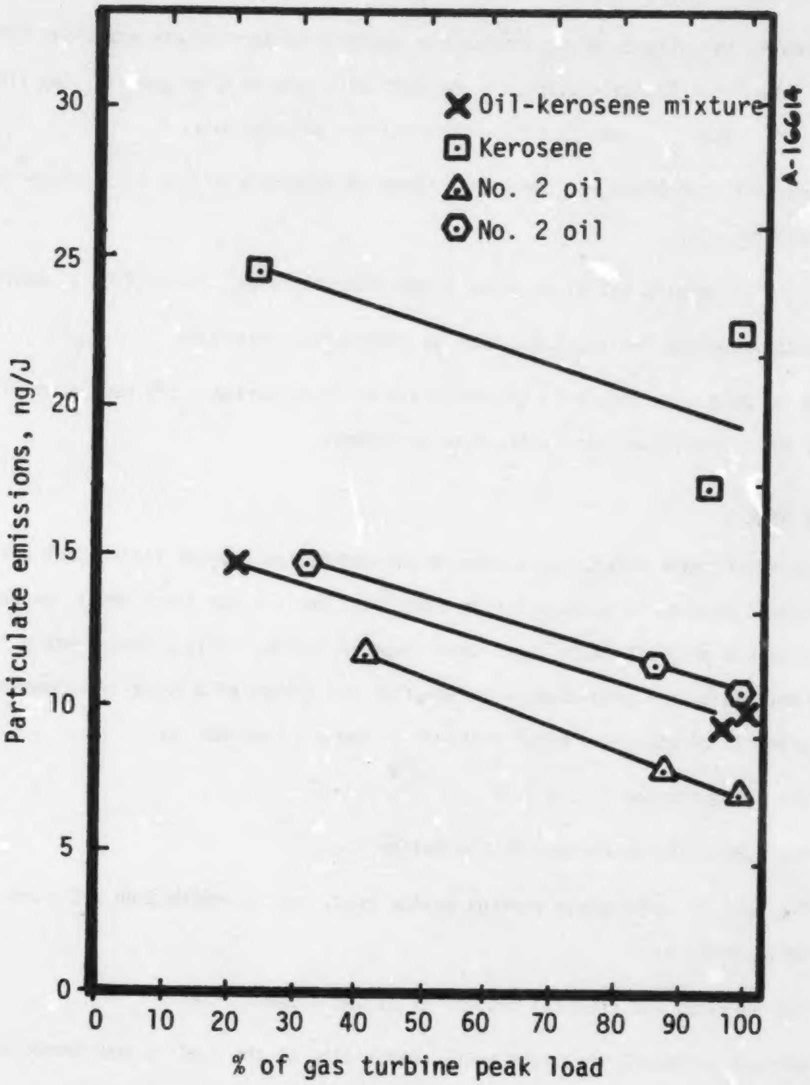


Figure 6-11. Gas turbine particulate emissions as a function of load (Reference 6-25).

The effect of water injection on particle emissions seems to be related to the specific injection method used (Reference 6-18). Some tests show smoke level reduction of 1.5 to 1.75 smoke spot numbers when water injection is used. Other tests, however, indicate increased particulate emissions with water injection at peak load.

6.2.3.5 Summary

In summary, the effects of NO_x combustion controls on particulate emissions from stationary sources have been insufficiently studied. The available data are, in general, too limited to form firm conclusions. However, some tentative observations are possible:

- Only off-stoichiometric combustion seems to adversely affect particulate emissions from boilers
- All NO_x controls except derating cause increased smoke levels from IC engines
- Load reduction increases gas turbine particulate emissions

More substantial data — particularly on particle size distribution — are needed to fully assess the effects that NO_x controls have on particulate emissions.

6.2.4 Trace Metals

Emissions of trace metals are a concern for combustion sources firing coal and residual oil. They are a lesser problem in sources firing distillate fuels since trace metal concentrations in distillate oils are generally much lower than those in residual oils. Trace metals from stationary sources are emitted to the atmosphere with the flue gas either as a vapor or condensed on particulate. The quantity of any given metal emitted, in general, depends on:

- Its concentration in the fuel
- The combustion conditions in the boiler
- The type of particulate control device used, and its collection efficiency as a function of particle size
- The physical and chemical properties of the element itself

For present purposes, the trace metal composition of the fuel is considered a given quantity, not subject to manipulation. Therefore although composition has a controlling effect on the absolute trace metal emissions from a combustion source, it is not considered as a factor to explain the effects NO_x controls have on incremental trace metal emissions.

It has become widely recognized that some trace metals tend to concentrate in certain waste particle streams from a boiler (bottom ash, collector ash, flue gas particulate), while others do not (References 6-26 through 6-32). Based on this phenomenon, three classes of partitioning metals have been defined (Reference 6-26).

- Class I: 20 metals (Al, Ba, Ca, Ce, Co, Eu, Fe, Hf, K, La, Mg, Mn, Rb, Sc, Si, Sm, Sr, Ta, Th, and Ti). These are found in the bottom ash or slag, the particle collector inlet flyash, and the collector outlet flyash in approximately the same mass concentrations.
- Class II: 9 metals (As, Cd, Cu, Ga, Pb, Sb, Se, Sn, and Zn). These are not usually found in bottom ash or slag, but are found in flyash. Mass concentrations in particle collector inlet flyash are generally less than in collector outlet flyash.
- Class III: Hg, and possibly Se. These are usually emitted as vapors in the flue gas.

Another set of elements (Cr, Cs, Na, Ni, U, and V) exhibits properties intermediate between Classes I and II.

Other work has shown that the Class II metals, As, Cd, Pb, Sb, Se, and Zn, along with Ni, Cr, and V become increasingly more concentrated in flyash particles as particle size decreases (Reference 6-27). Cd, Pb, Ni, Sb, Se, Sn, V and Zn all appear to have a mass mean diameter (MMD) of less than 1 μm in the atmosphere. The more common Class I metals, Fe, Al, and Si, have MMDs of 2.5 to 7.0 μm (Reference 6-33).

The most logical explanation for this segregation behavior involves a volatilization-condensation mechanism (Reference 6-26). In its simplest form, the argument says that Class I metals have boiling points sufficiently high that they are not volatilized in the combustion zone. Instead, they form a melt of relatively uniform concentration, which becomes both bottom ash or slag, and flyash. Thus, Class I elements remain in a condensed phase throughout the boiler and show little partitioning with particle size. By contrast, Class II metals have boiling points below peak combustion temperatures, so they are volatilized in the combustion zone and do not become incorporated in the slag. As combustion gases cool by traveling through the boiler, these elements either form condensation nuclei or condense onto other available solid surfaces (predominantly Class I mineral particles). Since the available surface area to mass ratio increases as particle size decreases, the Class II elements concentrate in small particles. This partitioning mechanism is further substantiated by observations that certain Class II metals exhibit higher surface concentrations than bulk concentrations in fine particles (Reference 6-34).

This simple mechanism described above does not fully account for all experimental observations. For example, Ca and Cu behave as high boiling point metals, whereas Rb, Cs, and Mg behave as volatile elements. Therefore, the volatilization-condensation mechanism has been extended as follows (Reference 6-24):

- Trace elements in coal are present as aluminosilicates, sulfides, and organometallics
- On combustion, the aluminosilicates melt to form slag or bottom ash, and flyash
- In the reducing atmosphere during initial stages of combustion, metal sulfides are reduced to vapor phase metal; at the same time the organic matrix of organometallics oxidizes, leaving volatilized metal
- Volatilized metals may themselves become oxidized to less volatile oxides
- As the combustion gas cools, these volatile species condense onto available solid surfaces, and concentrate in small particles
- Since slag and flue gas are in contact for only a short time, little volatile condensation in slag occurs

This extended mechanism is indirectly supported by the fact that Class I metals are largely geochemical lithophiles (readily associated with aluminosilicate minerals), while Class II metals are largely chalcophiles (readily incorporated into sulfide minerals).

In all mechanisms the Class III metals, Hg and to some extent Se, remain vaporized through the stack and are emitted as flue gas vapor components. Some 90 percent of Hg emissions (Reference 6-35) and about 20 percent of Se emissions (Reference 6-26) are emitted as vapors.

Regardless of the exact mechanism for the trace metal partitioning phenomenon, the partitioning significantly influences trace metal emissions from combustion sources with particulate control devices. All particle collection devices are more efficient at collecting large particles than small particles. Since Class II metals in flyash occur in smaller particles than Class I metals, a larger fraction of the Class II elements introduced into a boiler will be emitted from sources equipped with particulate control units.

This behavior is illustrated by recent trace metal emissions data from industrial boilers (Reference 6-36). Figure 6-12 shows the concentration of several Class I metals measured in particle samples from different points in a coal-fired industrial boiler. Figure 6-13 shows the same profile for several Class II elements. As the partitioning theory predicts, the concentration of Class I metals remains fairly constant throughout the boiler. On the other hand, flyash

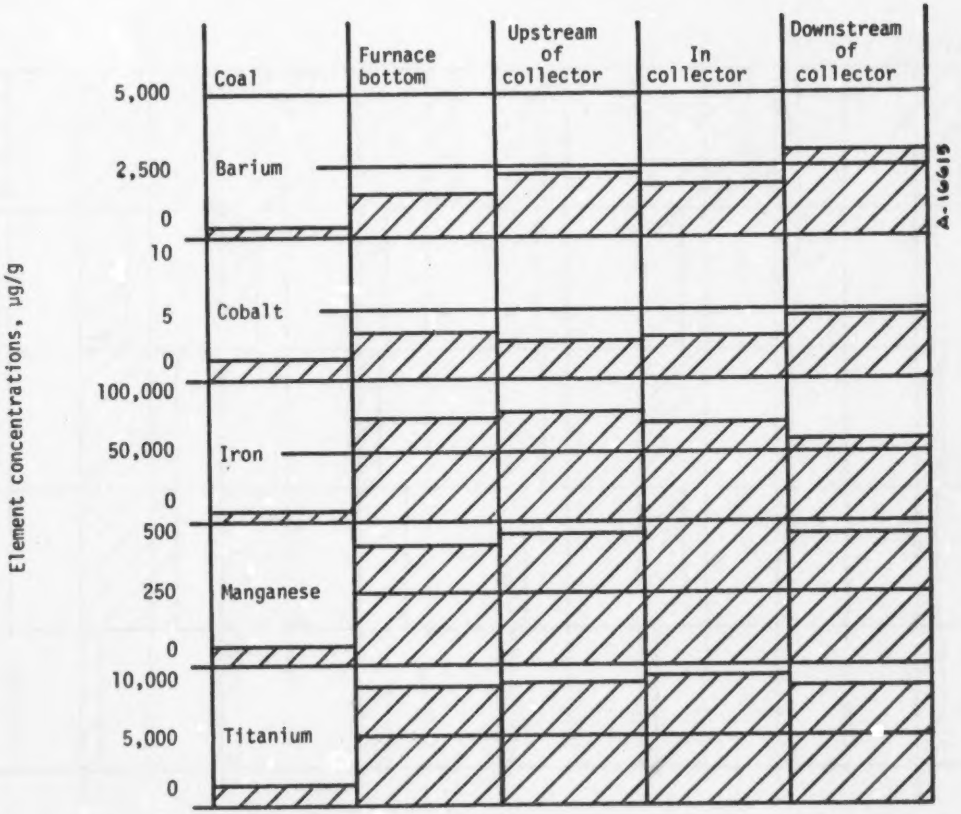


Figure 6-12. Partitioning of Class I elements (Reference 6-36).

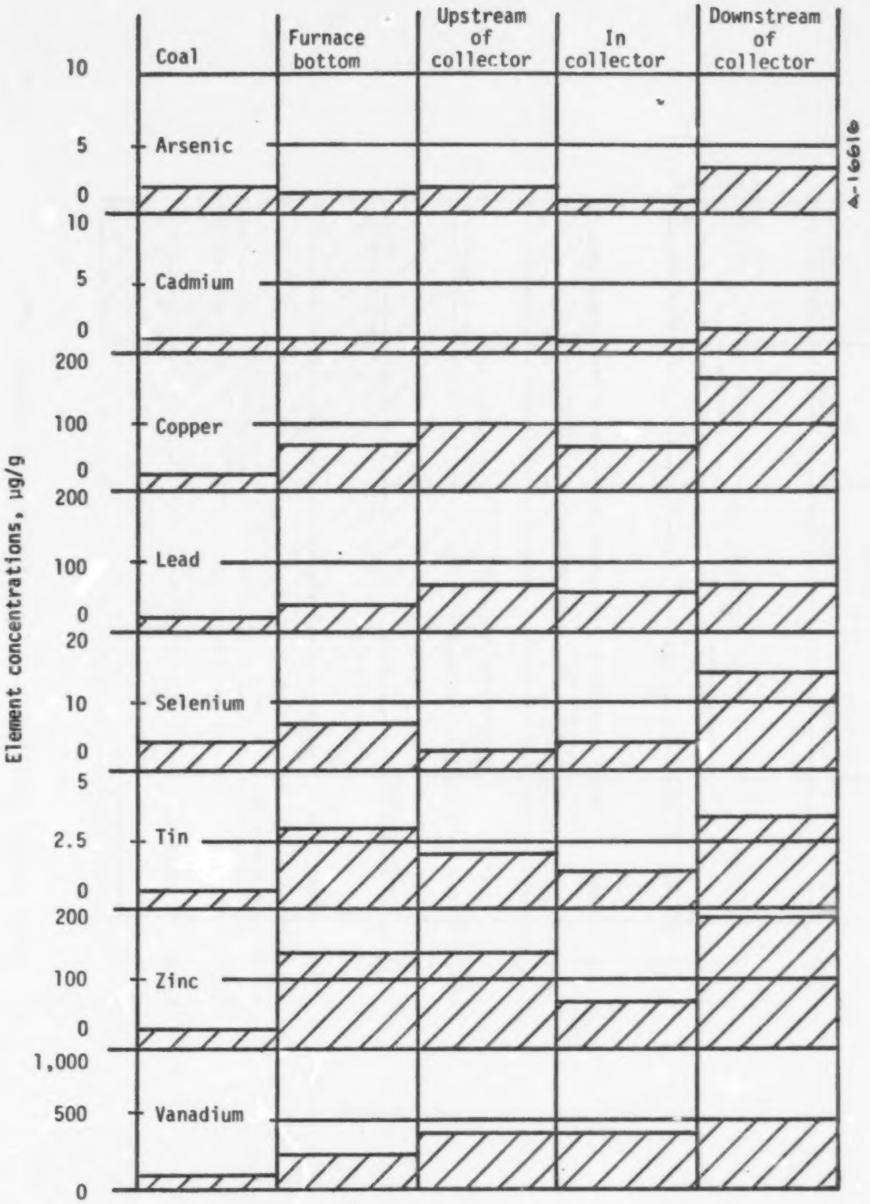


Figure 6-13. Partitioning of Class II elements (Reference 6-36).

concentrations of Class II elements increase toward the flue gas exit. The expected increase in concentrations in the collector effluent ash over collector inlet ash and collected ash is quite significant.

By understanding trace metal partitioning and concentration in fine particulate, it is possible to postulate the effects NO_x combustion controls will have on incremental trace metal emissions. Several NO_x controls for boilers result in lowered peak flame temperatures (off-stoichiometric combustion, flue gas recirculation, reduced air preheat, load reduction, and water injection). The volatilization-condensation theory predicts that if the combustion temperature is reduced, less Class II metal will initially volatilize, hence less will be available for subsequent condensation. Under these conditions (lowered flame temperature), it is expected that less Class II metal (the segregating trace metals discussed in Section 6.1) will be redistributed to small particulate. Therefore, in boilers with particulate controls, lowered volatile metal emissions should result. Class I metal (the nonsegregating trace metals discussed in Section 6.1) emissions should remain relatively unchanged.

Lowered local O_2 concentrations are also expected to affect segregating metal emissions from boilers with particle controls. Lowered O_2 availability decreases the possibility of volatile metal oxidation to less volatile oxides. Under these conditions Class II metals should remain in the vapor phase into the cooler sections of the boiler. More redistribution to small particles should occur and emissions should increase. Again, nonsegregating metal emissions should be unaffected. This behavior is expected when low excess air is implemented. Other combustion NO_x controls which decrease local O_2 concentrations (OSC and flue gas recirculation) also reduce peak flame temperature. For these, the effect of lowered combustion temperature is expected to predominate.

The effect of NO_x combustion controls on segregating metal emissions from combustion sources without particle collection devices should be marginal at best. Particle redistribution will not affect mass emissions because all particulate produced is emitted from these sources. However, since trace metal condensation on internal boiler surfaces undoubtedly occurs, conditions which decrease the extent of Class II metal volatilization (lowered peak flame temperature) should cause a slight increase in segregating metal emissions. Conversely, conditions which increase metal volatility (low local O_2 concentrations) should cause slight decreases in volatile metal emissions.

No data currently exist to document the above speculations. However, such data should be easy to obtain in forthcoming emissions assessment programs, if the effects of NO_x controls are studied in test matrices. Obtaining such data should be given relatively high priority since 8 of the 20 most toxic elements in air are Class II metals (Reference 6-37). Changes in the emission levels for these metals can have significant environmental impact.

6.2.5 Sulfates

Ambient sulfate levels are a matter of increasing concern in regions with large numbers of combustion sources firing sulfur-bearing coal and oil (notably, the northeast region of the U.S.). Although the direct health effects of high ambient sulfate levels are currently unclear (References 6-38 and 6-39), high sulfate aerosol concentrations are known to decrease visibility and aggravate acid precipitation phenomena.

Ambient sulfates are comprised of directly emitted sulfates (primary sulfates) and those derived from the atmospheric oxidation of SO_2 (secondary sulfates). However, the relative contribution of each of these to ambient levels is presently unclear. Recent estimates indicate that primary sulfates comprise about 5 to 20 percent of the ambient sulfate on a regional basis (Reference 6-39). However, regional transport processes are extremely important in determining local ambient levels, especially in the Northeast. Consequently, it is difficult to separate the effect of secondary sulfate production from the effect of transported primary sulfate on a region's ambient sulfate level.

Although the plume chemistry of secondary sulfate formation has not yet been fully described, it is generally recognized that SO_2 can be oxidized to sulfate through the five mechanisms summarized in Table 6-16. Of these, it is generally concluded that the first mechanism is of minor importance (Reference 6-39). Similarly, the importance of mechanism 3 is thought to be minor when compared to mechanisms 4 and 5.

The relative effects of mechanisms 2, 4, and 5 are currently unknown. Ambient vanadium appears to be strongly related to ambient sulfate, even though vanadium is a high temperature SO_2 oxidation catalyst and is ineffective at room temperature (Reference 6-41). Weaker correlations exist between ambient sulfate and ambient iron and manganese. However, ambient sulfate does not correlate with ambient NO_2 at all (Reference 6-39). These facts would seem to indicate that the catalytic mechanisms are the more significant in producing secondary sulfates.

On the other hand, recent power plant plume measurements show that the conversion of SO_2 to sulfate aerosol is essentially zero for the first two hours of plume residence time, but increases quite rapidly thereafter (Reference 6-42). This could be due to solution pH limitations. It is interesting, however, that this time compares quite favorably to the 20 to 90 minute residence time required for the NO/NO_x ratio in a plume to reach an "equilibrium" value of about 0.5, as reported by Gordon et al., (Reference 6-43). It is known that NO inhibits SO_2 oxidation (Reference 6-44) presumably by scavenging oxidizing agents (notably ozone). However work by Davis et al., (Reference 6-45) has attempted to suggest an even more intimate relationship between NO_2, NO, and

TABLE 6-16. MECHANISMS THAT CONVERT SULFUR DIOXIDE TO SULFATES (Reference 6-40)

Mechanism	Overall Reaction	Factors on Which Sulfate Formation Primarily Depends
1. Direct photo-oxidation	$SO_2 \xrightarrow[\text{water}]{\text{light, oxygen}} H_2SO_4$	Sulfur dioxide concentration, sunlight intensity
2. Indirect photo-oxidation	$SO_2 \xrightarrow[\text{organic oxidants, hydroxyl radical (OH·)}]{\text{smog, water, } NO_x} H_2SO_4$	Sulfur dioxide concentration, organic oxidant concentration, OH, NO_x
3. Air oxidation in liquid droplets	$SO_2 \xrightarrow{\text{liquid water}} H_2SO_3$ $NH_3 + H_2SO_3 \xrightarrow{\text{oxygen}} NH_4^+ + SO_4^=$	Ammonia concentration, pH
4. Catalyzed oxidation in liquid droplets	$SO_2 \xrightarrow[\text{heavy metal ions}]{\text{oxygen, liquid water}} SO_4^=$	Concentration of heavy metal (V, Fe, Mn) ions, pH
5. Catalyzed oxidation on dry surfaces	$SO_2 \xrightarrow[\text{carbon, water}]{\text{oxygen, particulate}} H_2SO_4$	Carbon particle concentration (surface area)

SO_2 oxidation. Existence of this relationship is coupled with in-plume production of ozone and the appearance of an "ozone bulge" within the plume. In support, Levy and Spicer (Reference 6-46) conclude that, although Davis' postulated reaction sequence is questionable, the possiblity of interactions between NO_x photochemistry and sulfate production does exist and certainly deserves further elucidation.

Regardless of the possible impact of secondary sulfate production on ambient sulfate levels, it is clear that keeping primary sulfate emissions to a minimum is highly desirable. Since some 98 percent of the sulfur introduced into a combustion source generally appears in the flue gas, the present discussion will assume that one has no control over total sulfur oxide emissions (the existence of fuel desulfurization and flue gas desulfurization techniques is ancillary). Therefore, the focus here will be on ways to keep the $SO_4^=/SO_2$ ratio at a minimum.

In the present discussion, primary sulfate emissions will be defined as all sulfate emitted from the stack plus the amount produced in about the first half mile of plume travel. These sulfates may exist as either sulfuric acid (H_2SO_4) or as metal or ammonium sulfates (denoted here as $SO_4^=$). The fraction of H_2SO_4 (measured as SO_3) in the sulfur oxides emitted from boilers ranges from 1 to 3 percent from coal-fired sources to 5 to 9 percent for oil-fired boilers (Reference 6-47). $SO_4^=$ emission levels have not yet been clearly established, though it is thought that these at least equal H_2SO_4 emissions (Reference 6-48).

The precise mechanisms for the formation of sulfates in combustion systems are not completely understood. However, it seems clear that two processes contribute to final flue gas sulfate levels. The first is homogeneous SO_2 oxidation in the flame through the reaction:

$$SO_2 + O + M = SO_3 + M \tag{6-1}$$

Although SO_2 is the thermodynamically favored product at high temperatures, it is currently thought that some SO_3 is formed through Equation (6-1). Subsequent rapid gas quenching then freezes the system into a nonequilibrium state. In any event, any SO_3 formed through this reaction will, under flue gas conditions, combine with available water vapor to form vapor phase sulfuric acid. This sulfuric acid will then either absorb or condense onto available particulate and be emitted as an aerosol or, in the absence of sufficient particulate, as a vapor which condenses to acid mist as soon as plume temperature drops below its acid dew point.

The second important sulfate formation mechanism is catalyzed heterogeneous SO_2 oxidation in post-combustion regions by flue gas particulates and internal boiler deposits. Several potential oxidation catalysts exist in suspended and deposited flue gas particulate, including vanadium, nickel, iron, manganese oxides, and carbon (soot). Vanadium pentoxide (V_2O_5) is a well known and quite effective oxidation catalyst in the 400 to 700°C temperature range. It is, in fact, used in the contact process for the manufacture of sulfuric acid. However, Fe_2O_3 also catalyzes SO_2 oxidation at 450 to 850C (Reference 6-49), and MnO_2 is an effective catalyst from room temperature to at least 340C (References 6-41, 6-50). Finally, Novakov (Reference 6-51) has recently shown that even freshly generated soot and graphite particles convert SO_2 to SO_3.

A third mechanism, usually considered to be of importance only in secondary sulfate formation, deserves some comment here. This is mechanism 4 in Table 6-16, catalytic oxidation in solution. Under normal conditions, the pH of near plume liquid droplets is low, approximately 3. At this pH, SO_2 solubility is quite low, so solution chemistry normally contributes negligibly to primary sulfate levels in the near plume. However, if sufficient quantities of a basic specie, such as ammonia, were present to neutralize these droplets, SO_2 solubility would increase dramatically, leading to significant amounts of sulfate production through solution catalysis in the near plume. Consequently, the use of post-combustion ammonia injection for NO_x control could possibly lead to significantly increased primary sulfate emissions. Of course, much further work is needed in this area before any conclusions can be substantiated.

It is important to note that each of the above mechanisms operates in a different region of a boiler, because each has different temperature requirements. This fact is illustrated in Figure 6-14, which shows the relative importance of each mechanism as a function of temperature regime and corresponding boiler region. In the flame zone, temperatures are high and sulfate is expected to be formed by rapid homogeneous gas phase oxidation. This corresponds to curve A in the figure. However, at somewhat lower temperatures, in the boiler's convective passes, homogeneous reaction rates are too slow to contribute significantly to sulfate formation. At these temperatures, catalytic mechanisms should be most important, as illustrated by curves B and B'. Curve C represents solution chemistry and curve D represents indirect photo-oxidation (mechanism 2 of Table 6-16). Both of these are normally of importance only in secondary sulfate production.

The relative importance of each mechanism in determining final sulfate levels is not presently known. Thus, two curves, B and B', are shown in Figure 6-14. (The two curves also indicate that the temperature range of importance is also uncertain.) However, it is currently thought that flyash/soot catalysis is at least as important a mechanism in forming sulfate as the high temperature homogeneous mechanism. This view is indirectly supported by the fact that H_2SO_4/SO_2 ratios from oil-fired

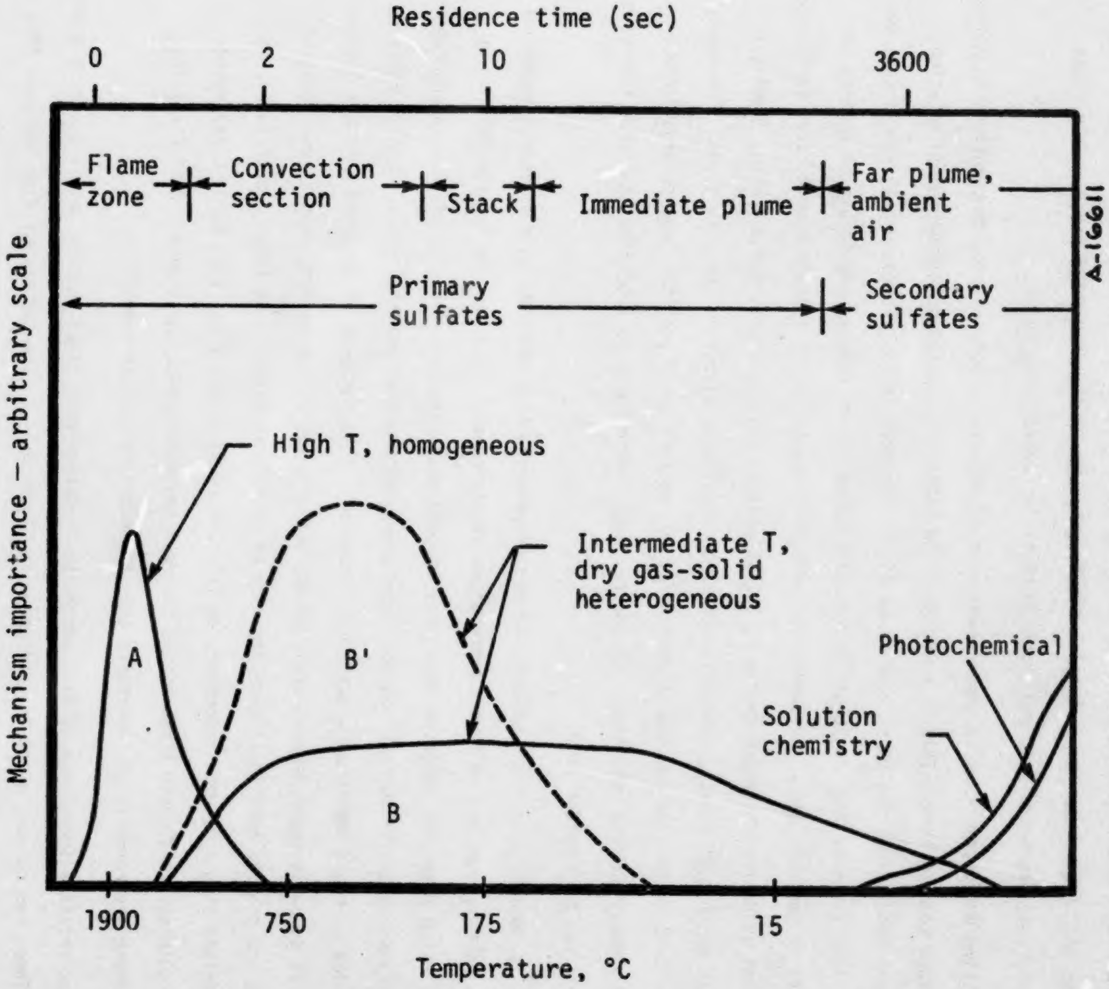


Figure 6-14. Sulfate formation regimes of importance (Reference 6-48).

sources are higher than those from coal-fired sources. Residual oils generally contain more vanadium and nickel than coal.

Based on the above, it is possible to speculate on the effects NO_x controls might have on primary sulfate production. Since primary sulfate emissions are largely dependent on combustion gas oxygen availability, boiler temperature-time history, and internal catalyst availability, combustion modifications which alter these parameters should affect the amount of SO_2 converted to sulfate.

Reduced oxygen availability should definitely tend to decrease primary sulfate emissions. Thus, NO_x controls which result in decreased local oxygen availability (e.g., low excess air firing and off-stoichiometric combustion) should result in lowered sulfate emission levels. In fact, Archer, et al., (Reference 6-52) have shown, in pilot scale work on two-stage combustion, that SO_3 levels leaving the first combustion stage can be reduced to essentially zero when this stage is fired fuel rich.

The effects of boiler temperature time history on sulfate production are significantly more difficult to sort out because of the lack of knowledge about in situ catalytic mechanisms and their relative importance with respect to homogeneous SO_2 oxidation. However, the effects of NO_x controls on boiler temperature profile and the effect of temperature on oxidation catalyst availability follow from the trace metal discussion presented in Section 6.2.4. Vanadium, nickel and their oxides, which are active SO_2 oxidation catalysts, are also metals which partition to fine particulate, as discussed in Section 6.2.4. Therefore, conditions which promote the redistribution of these metals to accessible surfaces (e.g., boiler tubes and other internal boiler surfaces in addition to flue gas particle surfaces) should promote increased sulfate production. Thus, as discussed in Section 6.2.4, combustion conditions which facilitate volatilization-condensation and partitioning, such as high peak flame temperatures, should promote SO_2 oxidation. Conversely, combustion controls which, for example, lower peak flame temperatures, should decrease sulfate productions.

Based on the above, it is expected that combustion modifications which lower local O_2 levels (such as low excess air firing), which lower peak flame temperature (such as flue gas recirculation, reduced air preheat, and water injection), or which do both (such as OSC), will decrease the amount of SO_2 oxidized to sulfate. Of course, care must be taken when implementing any of these controls not to stimulate excess particulate production. The catalytic effects of internally deposited soot or flyash could overcome the beneficial effects of lower O_2 concentration and reduced catalyst repartitioning.

Data confirming these conclusions, though sparse, do exist. Recent measurements have demonstrated the expected dependence of sulfate emissions on boiler excess air levels. Bennett and Knapp (Reference 6-53) have shown that particulate sulfate emissions increase with increasing boiler excess O_2 in oil-fired power plants. Homolya, et al., (Reference 6-47) report a similar increase in sulfate emissions as a percentage of total sulfur emissions with increasing excess O_2 in coal-fired boilers. Their data, shown in Figure 6-15, show a linear relationship between the sulfate fraction of emitted sulfur and boiler excess O_2.

Other data (Reference 6-54), shown in Table 6-17 also show that SO_3 emissions decrease when OSC is used to control NO_x.

The situation in coal-fired boilers equipped with electrostatic precipitators (ESPs) for particulate control deserves some further comment. It is well known that SO_3 (or more appropriately sulfuric acid) serves to condition low resistivity flyash and improve ESP performance in collecting these particles. Therefore, it is conceptually possible that a decrease in primary sulfate production could give rise to increased particulate sulfate emissions. Though the phenomenon seems somewhat unlikely, further work on this question is definitely needed.

The problem of acid smut emissions, which is also related to sulfate formation, also deserves some discussion here. Emissions of acid smut (large "globs" of highly acidic carbonaceous particulate) have been experienced recently in several residual oil-fired utility boilers in the U.S. Acid smuts are extremely corrosive and their large size (up to 100μ) leads to fallout in the vicinity of the power plant. They are thus of concern both for potential impact on both human health and welfare. Acid smut emissions have been experienced for many years in Europe due to their practice of firing heavy oil units at lower levels of excess air than was common in the U.S. (References 6-8 and 6-55 through 6-58).

Recently the problem has occurred when certain NO_x controls, notably off stoichiometric combustion combined with low excess air, are implemented on residual oil-fired units. It also invariably occurs in boilers which were originally designed to fire natural gas, but have been converted to oil firing because of fuel availability problems.

The exact reasons for the appearance of acid smut emissions are not clearly understood. However, it is clear that they are related to air heater design and the resulting final flue gas temperature. Since natural gas contains very little sulfur, acid mist condensation in and downstream of the air heaters has never been a concern. Therefore, air heaters in gas-fired boilers have been designed to give lower flue gas temperatures than corresponding air heaters in oil-fired

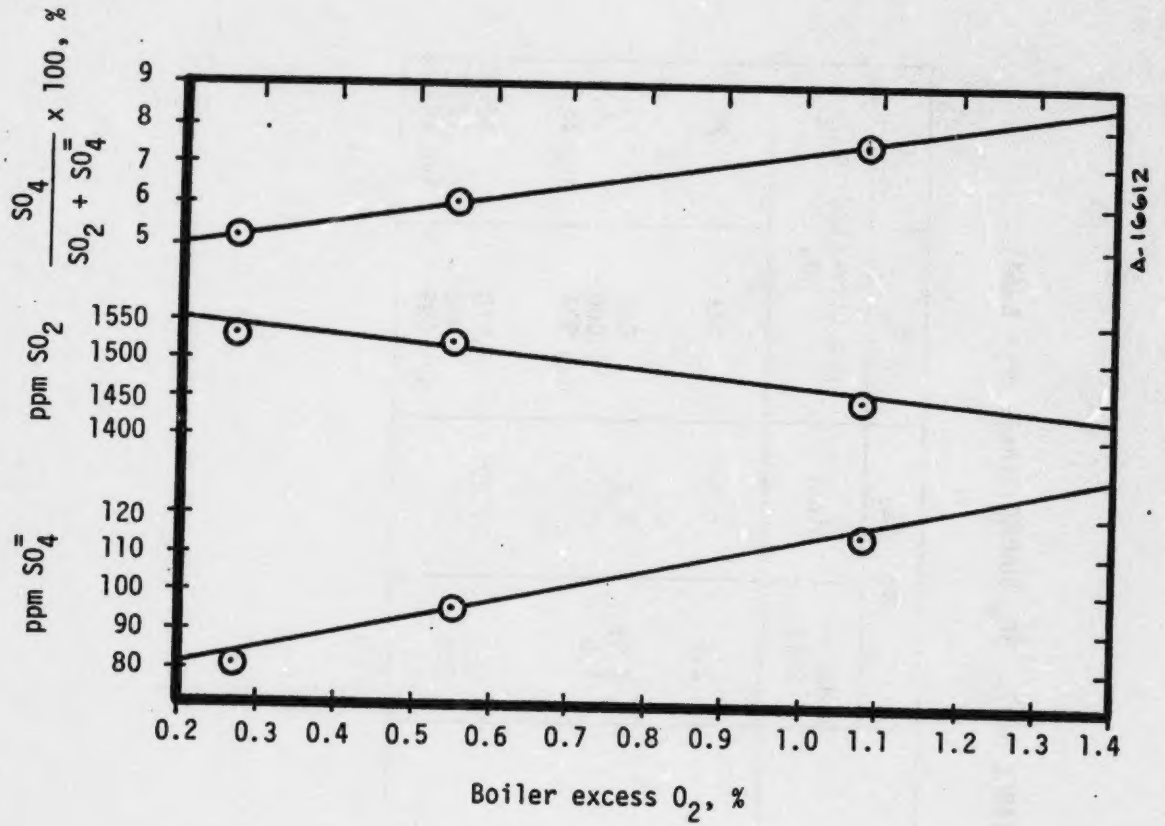


Figure 6-15. SO_2 conversion vs. excess oxygen (Reference 6-47).

TABLE 6-17. SO_x SUMMARY (Reference 6-54)

	O_2 (%)		SO_2	SO_3
	Boiler Exit	Stack	ppm Corrected to 3% O_2	
Baseline	2.9	6.8	944	28
LEA	1.55	5.7	948	13.5
	1.5		1,000	35.9
			Avg 974	Avg 25
OSC	3.1	7.72	1,010	14.0
	3.4	7.1	968	13.9
			Avg 989	Avg 14

units. However, when these same gas-fired units are switched to oil firing, it is possible for flue gas temperatures downstream of the air heater to approach the acid dew point. In the absence of particulate emissions, flue gas sulfuric acid would then condense and reevaporate through the ductwork and stack until ultimately emitted as a finely dispersed mist.

The appearance of acid smut emissions when implementing NO_x controls which enhance the production of soot particles suggests the possible next step in the smut formation mechanism. In the presence of sufficient particulate, flue gas sulfuric acid condenses onto particle surfaces in sufficient amounts to cause particle agglomeration. Agglomerated particles then deposit onto ductwork walls. These deposits continue to grow through further agglomeration until they become large enough to spall off the wall. Thus, emissions of wet acidic "globs" or acid smut occur.

In light of the above, acid smut emissions have been viewed as a combined sulfate production problem and particulate production problem. Attacks on the problem have included both reduction of acid formation and/or condensation and suppression of carbon formation or agglomeration. Table 6-18 summarizes process modifications used or proposed in Europe and the U.S. (References 6-55 through 6-58). It appears that incremental emissions of acid smut can be suppressed if addressed during control development. The potential for acid smut emissions should be considered when implementing NO_x controls on heavy oil-fired boilers with preheaters and without particle collection devices.

In summary, the postulated, and in some cases demonstrated, effects of most NO_x combustion controls on primary sulfates are to decrease emissions or leave them unchanged. However, since there are insufficient data to fully substantiate any real conclusion, it seems appropriate to consider incremental sulfate emissions due to NO_x combustion modifications of questionable concern, except in the case of acid smuts and use of post-combustion ammonia injection. Because ammonia injection may significantly increase near plume sulfate production through solution chemistry, its effects on residual sulfate should be considered of definite concern.

6.2.6 Organics

In the true sense, the class of organic compounds includes virtually all carbon-containing compounds except carbon monoxide and carbon dioxide. In the present discussion, however, "organics" will be used to describe only those species not included in the class of compounds referred to as the criteria pollutant, "hydrocarbons". Therefore, with few exceptions, hydrocarbon emissions, discussed in Section 6.2.2, will include essentially all organic compounds emitted in the vapor phase at flue gas temperature. The remaining organic emissions, discussed here, are composed

TABLE 6-18. SUMMARY OF PROCESS MODIFICATIONS TO REDUCE ACID SMUT FALLOUT
(References 6-55 through 6-58)

T-175

Principle	Candidate Techniques	Size Range Affected	Comments
1. Suppress buildup of acid smut	Frequent or continuous soot blow	Large particles	Acid smuts emitted in smaller, dispersable, size range; successfully tested at Eastern Utility; promising option
2. Prevent acid condensation	Reduced air preheat	Large particles	Reduced efficiency; possible smut buildup in stack at reduced size range
3. Neutralize acid smut	Additives: dolomite, limestone, MgO, NH_3	Large and small particles	Reduces (50%) but doesn't eliminate acid emissions; additives increase particle loading
4. Suppress SO_3 formation	Reduced excess air	Large and small particles	Increased efficiency; increased carbon and CO emissions; limited by NO_x control techniques
	Reduced load	Large and small particles	Not cost effective
	Reduced catalytic activity of superheater	Large and small particles	Additive coating is partially effective; operational problems
	Reduced sulfur in fuel; mixed distillate/resid. firing	Large and small particles	Distillate availability uncertain
5. Reduce carbon emissions	Increased excess air	Large and small particles	Reduced efficiency; increased SO_3
	Better firebox mixing	Large and small particles	Limited by NO_x controls
	Fuel pretreatment to remove heavy carbon compounds	Large and small particles	
6. Particle collection	Cyclone, ESP or baghouse	Large and small particles	Effective but costly

largely of compounds emitted from combustion sources in a condensed phase. These compounds can almost exclusively be classed into a group known variously as polycyclic organic matter (POM) or polynuclear aromatic hydrocarbons (PNA or PAH). The following discussion, then, treats POM emissions from stationary combustion sources and the effects of NO_x controls on these emissions. In addition, a discussion of nitrosamines is included in this subsection, since this class of compounds is quite important from an environmental health standpoint and is not discussed elsewhere.

Although polycyclic organic matter can conceivably be formed in the combustion of any hydrocarbon fuel, it is considered more of a problem when associated with soot (carbonaceous particulate) emissions from coal and oil-fired combustion equipment. POM is especially prevalent in the emissions from coal burning, because a large fraction of the volatile matter in coal (coal tar) is preexisting POM.

Although the precise mechanism of POM formation in flames is complex and variable, it is possible to form a relatively clear picture of the overall reaction. In a reducing atmosphere, at temperatures around 2,000K (conditions common in the center of flames) radical species of the form, $H\dot{C}=\dot{C}H$ and $RCH=\dot{C}H$, can rapidly combine and form large polynuclear aromatic molecules through radical chain propagation (References 6-2, 6-59). As combustion gas cools and chain propagation is quenched, a variety of POM species can remain when combustion is incomplete. Upon further cooling, these species condense and are emitted largely as soot or high carbon content particulate.

POM emissions have significant environmental impact because several species are highly carcinogenic (Reference 6-2). The fact that they generally exist as fine particulate (for reasons similar to those presented in Section 6.2.4 to explain trace metal partitioning to fine particles) makes them an even more serious health hazard.

It is important to again note that although POM formation is possible during methane combustion, the formation of these large aromatic molecules is facilitated by the presence of higher molecular weight radicals and C_2H_2. Thus, POM production is of only minor concern in gas-fired systems, of some concern in oil-fired sources, and of greatest concern in coal-fired equipment. Whatever the combustion source, it is clear that POM emissions should increase under conditions of poor combustion efficiency. Since NO_x combustion controls can lead to inefficient combustion and soot formation, if not carefully applied (especially low excess air and staged combustion), implementation of these controls can most certainly lead to increased POM formation.

Data to support this contention, however, are essentially nonexistent, largely because of the difficulty of sampling flue gas streams for POM containing particles and of accurately assaying samples for individual POM species. A recent field test program on oil-fired industrial boilers was to include sampling for POM emissions (Reference 6-36), but sampling train and analytical problems prevented useful data from being obtained. Thompson et al., recently reported the effects of off-stoichiometric combustion and flue gas recirculation on POM emissions from a coal-fired utility boiler (Reference 6-14). Their data, shown in Table 6-19, seem to indicate that POM emissions do increase with two-stage combustion. However, they state that the sampling and laboratory analysis procedures used in obtaining the data varied over the sample set. Thus, they conclude that POM emissions are not significantly affected by firing mode. In a third study, Bennett and Knapp (Reference 6-53) attempted to investigate the effects of boiler excess O_2 on POM emissions from an oil-fired utility boiler. They found that particulate carbon content increased with decreasing excess O_2. However, because POM assay data varied widely, even for baseline condition analyses, no conclusion regarding POM emissions was possible.

A few comments are in order here concerning an extremely toxic subclass of polynuclear aromatic hydrocarbons, the polychlorinated and polybrominated biphenyls (PCBs and PBBs). A theoretical assessment of the possibility of PCB formation in combustion sources has been recently completed (Reference 6-60). This study was prompted by a tentative identification (later proved false) of PCBs in stack emissions from a coal-fired utility boiler (Reference 6-61). The theoretical study concluded that, although PCB formation is thermodynamically possible during coal and residual oil (fuels which contain some chlorine) combustion, it is unlikely due to short reaction residence times and low chlorine concentrations. However, if PCBs are formed, they would be expected to occur under conditions which promote POM emissions. Still, other than the aforementioned tentative identification, PCBs have never been observed in combustion source emissions.

The second general compound category considered as an organic emission in the present discussion is the nitrosamines group. Nitrosamines (characterized by the N-nitroso group, N-N=0) are formed by the reaction of secondary or tertiary amines with nitrous acid. These N-nitroso compounds are of environmental concern because nearly 70 percent of these compounds have been found to be carcinogenic in all species of laboratory animals (Reference 6-62).

Primary nitrosamine emissions from various industrial sources may affect ambient levels. Three recent environmental assessments of these compounds (References 6-62, 6-63, and 6-64) have concluded that primary nitrosamine emissions from stationary combustion sources are nonexistent. There are at present, however, no data to support this contention.

Combustion sources do, however, emit the NO_x precursors to nitrous acid, one requisite ingredient in nitrosamine formation. Since nitrate formation from ambient NO_x is known to occur, it is theoretically possible for nitrosamines to be formed in polluted atmospheres containing secondary

TABLE 6-19. SUMMARY OF POM EMISSION TESTS
(Reference 6-14)

	Baseline ($\mu g/m^3$)[a]	2-Stage Combustion ($\mu g/m^3$)[a]	15% Gas Recirculation ($\mu g/m^3$)[a]	2-Stage + 15% Recirculation ($\mu g/m^3$)[a]
Anthracene/Phenanthrene	178.4	179.3	145.3	230.4
Methyl Anthracenes	53.4	48.5	89.4	98.3
Fluoranthene	51.5	110.3	24.7	43.7
Pyrene	15.1	52.1	23.3	46.9
Chrysene/Benz (A) Anthracene	0.3	--	--	--
Total POM	298.7	390.2	282.7	419.3
(Percent of Baseline)	(100)	(131)	(95)	(140)

[a] 3% O_2, dry basis.

and tertiary amines. From such considerations, it is clear that implementing NO_x controls in stationary combustion sources can only serve to decrease ambient nitrosamine levels. Thus, the incremental impact of NO_x controls on nitrosamines is beneficial.

6.2.7 Nitrates

Atmospheric nitrate exists in both organic and inorganic forms. Organic nitrate consists of alkyl nitrates and peroxyacylnitrates, of which the most important is peroxyacetylnitrate (PAN). PAN — which is by far the most abundant organic nitrate and is even the most abundant of all ambient nitrates (Reference 6-65) — is an eye irritant and causes damage to vegetation. Inorganic nitrates include nitric acid and the nitrate salts of various metals and ammonium ion, of which ammonium nitrate appears to be the most abundant (Reference 6-66). Inorganic nitrates exist in the atmosphere as nitrate aerosol. Although the direct health effects of ambient nitrate aerosols are largely unknown, atmospheric inorganic nitrate has become a matter of major concern as a contributor to acid precipitation.

Although the data are largely lacking, it appears at present that primary nitrate emissions from stationary or mobile combustion sources are insignificant. Ambient nitrate seems, instead, to be a direct result of secondary nitrate production from ambient NO_x precursors. Although the formation of inorganic nitrate in the atmosphere is not clearly understood, the reactions shown in Table 6-20 are believed to be important (Reference 6-46). These reactions are believed to be heterogeneous and therefore catalyzed by ambient particulate. The nitric acid produced through these reactions seems to be immediately neutralized. Ambient ammonia is the major neutralizing agent, giving rise to ammonium nitrate aerosol. The mechanism for PAN formation is more clearly understood, and is also shown in Table 6-20.

Since there are apparently no primary nitrate emissions from stationary combustion sources, the possible effects of combustion NO_x controls on these emissions are unimportant. Indeed, the use of NO_x controls should decrease ambient secondary nitrate levels by decreasing precursor compound emissions. This is, in fact, one important reason for controlling NO_x emissions.

One possible point of concern in the area of nitrate emission is the proposed use of ammonia injection for NO_x control. Recent evidence suggests that ambient ammonia levels may be a determining factor in nitrate aerosol formation (Reference 6-66). If this is the case, implementation of ammonia injection could possibly cause increased atmospheric nitrate aerosol production.

TABLE 6-20. NITRATE FORMATION MECHANISMS
(References 6-46, 6-66)

A. Inorganic Nitrate

$$6NO_2 + 3H_2O \rightleftarrows 3HNO_3 + 3HNO_2 \tag{1a}$$

$$3HNO_2 \rightleftarrows HNO_3 + 2NO + H_2O \tag{1b}$$

$$HO + NO_2 \rightarrow HNO_3 \tag{2}$$

$$NO_2 + O_3 \rightleftarrows NO_3 + O_2 \tag{3a}$$

$$NO_3 + NO_2 \rightleftarrows N_2O_5 \tag{3b}$$

$$N_2O_5 + H_2O \rightleftarrows 2HNO_3 \tag{3c}$$

B. PAN

$$R + CH_3CHO \rightleftarrows \text{Product} + CH_3CO \tag{4a}$$

$$CH_3CO + O_2 + M \rightleftarrows CH_3COO_2 + M \tag{4b}$$

$$CH_3COO_2 + NO_2 \rightleftarrows CH_3COO_2NO_2 \text{ (PAN)} \tag{4c}$$

6.3 EVALUATION AND SUMMARY

Based on the discussions in Sections 6.1 and 6.2, NO_x control techniques and pollutants can be classified into one of the following three groups according to potential for increased emissions:

- High potential emissions impact, where the data presented in Section 6.2 unambiguously show that applying the NO_x control results in significantly increased emissions of a specific pollutant
- Intermediate potential emissions impact, where the preliminary screening exercise in Section 6.1 indicates that the NO_x control could conceivably cause increased pollutant emissions, but confirming data are lacking, contradictory, or inconclusive
- Low potential emissions impact, where the data presented in Section 6.2 clearly show that specific pollutant emission levels decrease when the NO_x control is applied, or where the discussion in Section 6.1 definitely indicates a similar conclusion, even though data are lacking

These groupings appear in Tables 6-21, 6-22, and 6-23 for NO_x combustion controls applicable to boilers, IC engines, and gas turbines, respectively. These tables are arranged in matrix form, like Tables 6-2, 6-4, and 6-5 of Section 6.1, and note the level of potential environmental concern for each NO_x control technique/pollutant combination.

As Table 6-19 illustrates, applying preferred NO_x combustion controls to boilers should have few adverse effects on incremental emissions of CO, vapor phase hydrocarbons or particulates. It is true that indiscriminantly lowering excess air can have drastic effects on boiler CO emissions, and that particulate emissions can increase with off-stoichiometric combustion and flue gas recirculation. However, with suitable engineering during development and implementation of these modifications, adverse incremental emissions problems can be minimized. In contrast, residual emissions of sulfate, organics, and trace metals have intermediate to high potential impact associated with applying almost every combustion control. For trace metal and organic emissions, substantiating data are largely lacking, but fundamental formation mechanisms give cause for justifiable concern. In the case of sulfate emissions, fundamental formation mechanisms suggest that these emissions should remain unchanged or decrease with all controls except ammonia injection. However, complex interactive effects are difficult to elucidate, and this pollutant class is sufficiently hazardous to justify expressing some concern in the present absence of conclusive data. The potential effects of post-combustion ammonia injection on plume sulfate formation deserve special attention.

TABLE 6-21. EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS APPLIED TO BOILERS

NO_x Control	Incremental Emission						
	CO	Vapor Phase HC	Sulfate	Particulate	Organics	Segregating Trace Metals	Nonsegregating Trace Metals
Low Excess Air	++	0	+	0	++	+	0
Staged Combustion	0	0	+	+	++	+	0
Flue Gas Recirculation	0	0	+	+	+	+	+
Reduced Air Preheat	0	0	+	0	+	0	+
Reduced Load	0	0	+	0	+	0	0
Water Injection	0	0	+	+	+	0	0
Ammonia Injection	0	0	++	+	0	+	0

Key: ++ denotes having high potential emissions impact
+ denotes having intermediate potential emissions impact, data needed
0 denotes having low potential emissions impact

TABLE 6-22. EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS APPLIED TO IC ENGINES

NO_x Control	Incremental Emission						
	CO	Vapor Phase HC	Sulfate	Particulate	Organics	Segregating Trace Metals	Nonsegregating Trace Metals
Retard Ignition	++	+	0	++	+	0	0
Increase A/F Ratio	0	++	++	0	0	0	0
Decrease A/F Ratio	++	++	0	+	+	+	0
Exhaust Gas Recirculation	+	+	0	++	+	+	0
Decrease Manifold Air Temperature	0	++	+	0	0	+	0
Stratified Charge Cylinder Design	+	+	0	+	+	+	0
Derate	++	++	+	0	0	+	0
Increase Speed	+	+	0	+	+	+	0
Water Injection	+	++	0	+	+	+	0

Key: ++ denotes having high potential emissions impact
+ denotes having intermediate potential emission impact, data needed
0 denotes having low potential emissions impact

TABLE 6-23. EVALUATION OF INCREMENTAL EMISSIONS DUE TO NO_x CONTROLS APPLIED TO GAS TURBINES

NO_x Control	Incremental Emission						
	CO	Vapor Phase HC	Sulfate	Particulate	Organics	Segregating Trace Metals	Nonsegregating Trace Metals
Water or Steam Injection	++	+	0	+	+	+	0
Lean Primary Zone	0	0	+	0	0	+	0
Early Quench with Secondary Air	0	0	0	+	+	+	0
Increase Mass Flowrate	+	+	0	+	+	+	0
Exhaust Gas Recirculation	+	+	0	+	+	+	0
Air Blast/Air Assist Atomization	0	+	0	+	+	+	0
Reduced Air Preheat	0	0	+	0	0	+	0
Reduced Load	++	++	+	++	+	+	0

Key: ++ denotes having high potential emissions impact
+ denotes having intermediate potential emissions impact, data needed
0 denotes having low potential emissions impact

Table 6-22 shows that the incremental emissions of all pollutant classes except nonsegregating trace metals have either intermediate or high potential impact when applying NO_x controls to IC engines. Of primary concern are increased CO, vapor phase hydrocarbons (HC), and particulate (smoke) emissions. Of lesser concern are sulfates, organics, and segregating trace metals from engines burning high sulfur diesel fuels.

Similarly, NO_x controls applied to gas turbines can be expected to adversely affect all incremental emissions except nonsegregating trace metals, as Table 6-23 indicates. Again, increased sulfate, particulate, organic, and segregating trace metals are of some concern in those sources firing high sulfur diesel fuels. If residual oil firing in gas turbines increases, these concerns could become more serious. Presently, this appears unlikely due to materials problems, e.g., sulfidation with residual oils.

The incremental emission evaluations of Tables 6-21 through 6-23 are not intended to signify any potential for adverse environmental impact. Rather, the evaluation notes source/control/pollutant combinations for which emissions may increase due to the use of NO_x controls. Evaluation of potential adverse impact requires comparison of the source generated ambient pollutant concentration with an upper limit threshold concentration of the pollutant based on health or ecological effects. A preliminary attempt at such a comparison is made in Section 7. Prior to that, some conclusions may be drawn on the results in this section.

In general, the data on incremental multimedia emissions due to NO_x controls are very sparse. More data are available for flue gas emissions than for liquid or solid effluent streams. Even so, the only data which allow quantified conclusions are for emissions of criteria pollutants with the major source/control combinations. Data on sulfates, trace metals and organics (POM) are sparse, experimentally uncertain and highly dependent on fuel properties. Incremental emissions from liquid and solid effluent streams and during transient or nonstandard operation are almost nonexistent. Because of this, they have generally been excluded in the present evaluation. Test data from ongoing related programs and from the NO_x E/A test programs will be needed before the incremental emissions and impacts can be evaluated for other than flue gas emissions during standard operation.

Emissions of CO, HC, particulate (smoke) and SO_3 with or without NO_x controls have been constrained in the past for operational reasons rather than environmental impact. CO, HC and smoke emissions reduce efficiency and may present a safety hazard. SO_3 leads to acid condensation and corrosion. All of these emissions are sensitive to combustion process modifications for NO_x control. With the exception of SO_3, incremental emissions tend to increase with NO_x controls, particularly low excess air and off-stoichiometric combustion. Development experience has shown, however, that with proper engineering these emissions can generally be constrained under low-NO_x conditions. This is particularly true for factory-installed controls on new equipment. In this case, the flexibility for applying NO_x controls with minimal adverse impact is greater than for retrofit on existing equipment. In light of this situation, incremental emissions are seen more as a constraining criteria to be addressed during control development than as an immutable consequence of low-NO_x firing. Moreover, the constraint on emissions for satisfactory operational performance is generally more stringent than the constraint for acceptable environmental impact. The environmental constraints will be carried through the NO_x E/A impact assessments for all potentially significant pollutants, but they will need to be supplemented by operational constraints in some cases.

The situation for other flue gas pollutants is more uncertain. There is concern that conventional combustion process modifications — low excess air, off-stoichiometric combustion, flue gas recirculation — will increase emissions of sulfates, organics and segregating trace metals from sources firing coal or residual oil. It should be noted, however, that this conclusion is based on sparse data or, lacking that, on fundamental speculation. Clearly, more data are needed. Little is known on whether these emissions can be suitably constrained to acceptable levels during control development.

With the firing of clean fuels — natural gas and distillate oil — the main noncriteria pollutant class of concern is organics. This fact will make the testing and assessments of clean fuel sources — warm air furnaces, gas turbines, IC engines — simpler than for boilers and process furnaces firing residual oil or coal. Additionally, the clean fuel sources have no liquid or solid effluent streams. These considerations do not imply a priori that gas or distillate oil-fired equipment are more environmentally sound. Rather, the clean fuel sources can be assessed to the same level of detail as other sources for less effort.

In conclusion, there is reasonable concern that NO_x controls will increase incremental emissions of some pollutants. More data are needed to determine if incremental emissions have a significant environmental impact and to suggest corrective action if needed. In the next section, a preliminary screening of pollutants on the basis of impact is given and test priorities are discussed.

REFERENCES FOR SECTION 6

6-1. Vapor Phase Organic Pollutants — Volatile Hydrocarbons and Oxidation Products, National Academy of Sciences, Washington, 1976.

6-2. Particulate Polycyclic Organic Matter, National Academy of Sciences, Washington, 1972.

6-3. Smith, W. S., and R. A. Taft, "Atmospheric Emissions from Fuel Oil Combustion," USPHS Pub. No. 999-AP-2, November 1962.

6-4. Dismukes, E. B., "Conditioning of Fly Ash with Ammonia," in Symposium on Electrostatic Precipitation for the Control of Fine Particles, EPA-650/2-75-016, NTIS-PB 240 440/AS, pp. 257-287, January 1975.

6-5. Barrett, R. E., et al., "Field Investigation of Emissions from Combustion Equipment for Space Heating," EPA-R2-73-084a, NTIS-PB 223 148, June 1973.

6-6. Hall, R. E., et al., "A Study of Air Pollutant Emissions from Residential Heating Systems," EPA-650/2-74-003, NTIS-PB 229 697/AS, January 1974.

6-7. Dickerson, R. A., and A. S. Okuda, "Design of an Optimum Distillate Oil Burner for Control of Pollutant Emissions," EPA-650/2-74-047, NTIS-PB 236 647/AS, June 1974.

6-8. Offen, G. R., et al., "Control of Particulate Matter from Oil Burners and Boilers," EPA-450/3-76-005, April 1976.

6-9. Combs, L. P., and A. S. Okuda, "Residential Oil Furnace System Optimization — Phase I," EPA-600/2-76-038, NTIS-PB 250 878/AS, February 1976.

6-10. Hall, R. E., "The Effect of Water/Distillate Oil Emulsions on Pollutants and Efficiency of Residential and Commercial Heating Systems," Air Pollution Control Association Paper 75-09.4, June 1975.

6-11. Crawford, A. R., et al, "The Effect of Combustion Modification on Pollutants and Equipment Performance of Power Generation Equipment," in Proceedings of the Stationary Source Combustion Symposium, Volume III, EPA-600/2-76-152c, NTIS-PB 257 146/AS, June 1976.

6-12. Crawford, A. R., et al., "Field Testing: Application of Combustion Modifications to Control NO_x Emissions for Utility Boilers," EPA-650/2-74-066, NTIS-PB 237 344/AS, June 1974.

6-13. Hollinden, G. A., et al., "Evaluation of the Effects of Combustion Modifications in Controlling NO_x Emissions at TVA's Widow's Creek Steam Plant," in The Proceedings of the NO_x Control Technology Seminar, EPRI SR-39, February 1976.

6-14. Thompson, R. E., et al., "Effectiveness of Gas Recirculation and Staged Combustion in Reducing NO_x on a 560 MW Coal-Fired Boiler," in The Proceedings of the NO_x Control Technology Seminar, EPRI SR-39, February 1976.

6-15. Cato, G. A., et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers — Phase I," EPA-650/2-74-078a, NTIS-PB 238 920/AS, October 1974.

6-16. Cato, G. A., et al., "Field Testing: Application of Combustion Modifications to Control Pollutant Emissions from Industrial Boilers — Phase II," EPA-600/2-76-086a, NTIS-PB 253 500/AS, April 1976.

6-17. "Standard Support Document and Environmental Impact Statement — Stationary Reciprocating Internal Combustion Engines — Draft," Aerotherm Final Report on Contract 68-02-1318, Task 7, Acurex Corporation/Aerotherm Division, Mountain View, CA, November 1975.

6-18. "Standards Support and Environmental Impact Statement — An Investigation of the Best Systems of Emission Reduction for Stationary Gas Turbines — Draft," prepared for U.S. EPA, OAQPS, July 1976.

6-19. Surprenent, N., et al., "Preliminary Emissions Assessment of Conventional Stationary Combustion Systems," GCA-TR-75-26-G(1), GCA Corporation, Bedford, MA., January 1976.

6-20. Gillis, B. G., "Production and Emissions of Solids, SO_x and NO_x from Liquid Fuel Flames," Journal of the Institute of Fuel, pp. 71-76, February 1973.

6-21. Kamo, R., et al., "The Effect of Air-Fuel Mixing on Recirculation in Combustion," Paper CP-62-12, API Research Conference on Distillate Fuel Consumption, June 1962.

6-22. Heap, M. P., et al., "Reduction of Nitrogen Oxide Emissions from Package Boilers," Revised Draft Final Report, EPA Contract 68-02-0222, Ultrasystems, Inc., Irvine, CA, 1976.

6-23. Bascom, R. C., et al., "Design Factors that Affect Diesel Emissions," SAE Paper 710484, July 1971.

6-24. Hills, F. J., et al., "CRC Correlation of Diesel Smokemeter Measurements," SAE Paper 690493, May 1969.

6-25. Coppersmith, F. M., et al., "Con Edison's Gas Turbine Test Program: A Comprehensive Evaluation of Stationary Gas Turbine Emission Levels," Paper 74-12, 67th Annual APCA Meeting, June 1974.

6-26. Klein, D. H., et al., "Pathways of Thirty-Seven Trace Elements Through Coal-Fired Power Plant," Environmental Science and Technology, Vol. 9, No. 10, pp. 973-979, October 1975.

6-27. Davison, R. L., et al., "Trace Elements in Fly Ash," Environmental Science and Technology, Vol. 8, No. 13, pp. 1107-1113, December 1974.

6-28. Kaakinen, J. W., et al., "Trace Element Behavior in Coal-Fired Power Plant," Environmental Science and Technology, Vol. 9, No. 9, pp. 862-869, September 1975.

6-29. Cato, G. A., and R. A. Venezia, "Trace Metal and Organic Emissions of Industrial Boilers," Paper 76-27.8, 69th Annual APCA Meeting, June 1976.

6-30. "Coal-Fired Power Plant Trace Element Study, Vol. I, A Three Station Comparison," Radian Corp. report for EPA Region VIII, September 1975.

6-31. Gladney, E. S., et al., "Composition and Size Distributions of Atmospheric Particulate Matter in Boston Area," Environmental Science and Technology, Vol. 8, No. 6, p. 551, June 1974.

6-32. Ensor, D. S., et al., "Elemental Analysis of Fly Ash from Combustion of a Low Sulfur Coal," Paper 75-33.7, 68th Annual APCA Meeting, June 1975.

6-33. Lee, R. E., Jr., et al., "National Air Surveillance Cascade Impactor Network II: Size Distribution Measurements of Trace Metal Components," Environmental Science and Technology, Vol. 6, No. 12, pp. 1025-1030, November 1972.

6-34. Bolton, N. E., et al., "Trace Element Measurements at the Coal-Fired Allen Steam Plant," Progress Report, February 1973 through July 1973, ORNL-NSF-EP-62, 1974.

6-35. Billings, C. E., et al., "Mercury Balance on a Large Pulverized Coal-Fired Furnace," J. APCA, Vol. 23, No. 9, pp. 773-777, September 1973.

6-36. Cato, G. A., "Field Testing: Trace Element and Organic Emissions from Industrial Boilers," EPA-600/2-76-086b, NTIS-PB 261 263/AS, October 1976.

6-37. Vitez, B., "Trace Elements in Flue Gases and Air Quality Criteria," Power Engineering pp. 56-60, January 1976.

6-38. Hegg, D. A., et al., "Reactions of Nitrogen Oxides, Ozone, and Sulfur in Power Plant Plumes," EPRI EA-270, September 1976.

6-39. Richards, J., and R. Gerstle, "Stationary Source Control Aspects of Ambient Sulfates: A Data Base Assessment," PedCo Final Report, EPA Contract No. 68-02-1321, Task 34, PedCo Environmental, Cincinnati, OH, February 1976.

6-40. "Position Paper on Regulation of Atmospheric Sulfates," EPA-450/2-75-007, September 1975.

6-41. Corn, M., and R. T. Cheng, J. APCA, Vol. 22, p. 870, 1972.

6-42. Husai, R. B., et al., "Particulate Sulfur Formation in Power Plant, Urban and Regional Plumes," Paper 13d, AIChE 82nd National Meeting, September 1976.

6-43. Gordon, G. E., "Study of the Emissions from Major Air Pollution Sources and Their Atmospheric Interactions," NSF-RA-E-74-059, NTIS-PB 242 581, October 1974.

6-44. Bradstreet, J. W., "Effects of Nitric Oxide on the Photochemical Oxidation of Sulfur Dioxide in Dilute Gas-Air Mixtures," Paper 73-113, 66th Annual APCA Meeting, 1973.

6-45. Davis, D. D., et al., Science, Vol. 186, p. 733, 1974.

6-46. Levy, A., and C. W. Spicer, "The Atmospheric Chemistry of NO_x," presented at the 69th National AIChE Meeting, November 1976.

6-47. Homolya, J. B., et al., "A Characterization of the Gaseous Sulfur Emissions from Coal and Coal-Fired Boilers," presented at the 4th National Conference on Energy and the Environment, Cincinnati, OH, October 1976.

6-48. Wendt, J. O. L., University of Arizona, Tucson, AZ, personal communication, January 1977.

6-49. Wichert, K., "Chemical Reactions in the Combustion Chamber of a Slag Tap Boiler," Brennstoff-Warme-Kraft, Vol. 9, pp. 104-118, March 1957.

6-50. Vogel, R. F., et al., "Reactivity of SO_2 with Supported Metal Oxide — Aluminum Sorbents," Environmental Science and Technology, Vol. 8, No. 5, pp. 432-436, May 1974.

6-51. Novakov, T., et al., "Sulfates as Pollution Particulates: Catalytic Formation on Carbon (Soot) Particles," Science, Vol. 186, pp. 259-261, October 18, 1974.

6-52. Archer, J. S., et al., "Multiphase Combustion of Residual Fuel Oil," J. Inst. Fuel, Vol. 43, pp. 397-404 and 451-460, 1970.

6-53. Bennett, R. L., and K. T. Knapp, "Chemical Characterization of Particulate Emissions from Oil-Fired Power Plants," presented at the 4th National Conference on Energy and the Environment, Cincinnati, OH, October 1976.

6-54. Hall, R. E., CRB, IERL, U.S. EPA, personal communication.

6-55. Remeysen, J., "Operations of Large Boilers at Very Low Excess-Air Levels," Paper 1 in Current Development in Fuel Utilization, the Institute of Fuel, 1964.

6-56. Niepenberg, H., "Combustion Control of Oil-Firing Systems Operated at Low Excess Air Levels," Paper 5 in Third Liquid Fuels Conference: Applications of Liquid Fuels, The Institute of Fuel, 1966.

6-57. Jackson, P. J., "Generating Stations Efficiencies," Paper 8 in Third Liquid Fuels Conference: Applications of Liquid Fuels, The Institute of Fuel, 1966.

6-58. "Chemistry and Metallurgy," Vol. 5 in Modern Power Station Practice, Central Electricity Generating Board, Pergamon Press, New York, 1971.

6-59. Bittner, J. D., et al., "The Formation of Soot and Polycyclic Aromatic Hydrocarbons in Combustion Systems," in Proceedings of the Stationary Source Combustion Symposium, Vol. I, EPA-600/2-76-152a, NTIS-PB 256 320/AS, June 1976.

6-60. Knierien, H., Jr., "A Theoretical Study of PCB Emissions from Stationary Sources," Monsanto Research Corporation, Dayton, OH, Report MRC-DA-577, September 1976.

6-61. Cowherd, C., Jr., et al., "Hazardous Emission Characterization of Utility Boilers," EPA-650/2-75-066.

6-62. "Scientific and Technical Assessment Report on Nitrosamines," EPA-600/6-77-001, November 1976.

6-63. Walker, P., et al., "Environmental Assessment of Atmospheric Nitrosamines," Mitre Corp., McLean, VA, MTR-7152, February 1976.

6-64. "Assessment of Scientific Information on Nitrosamines," Report of the ad hoc Study Group, U.S. EPA, Science Advisory Board, August 1976.

6-65. Stevens, E. R., et al., "Recent Developments in the Study of the Organic Chemistry of the Atmosphere," J. APCA, Vol. 6, p. 159, 1969.

6-66. Grosjean, D., et al., "The Concentration, Size Distribution, and Modes of Formation of Particulate Nitrate, Sulfate, and Ammonium Compounds in the Eastern Part of the Los Angeles Basin," Paper 76-20.3, 69th Annual APCA Meeting, June 1976.

SECTION 7

ENVIRONMENTAL ASSESSMENT PRIORITIES

The NO_x E/A program priorities summarized in this section relate directly to the needs and approach discussed in the Preface and Introduction of this report. The needs to be addressed by the NO_x E/A are:

- Assess current and impending combustion modification applications to quantify environmental, economic and operational impacts
- Assess emerging advanced technology to guide control development
  - Identify potential adverse impacts which should be addressed in the control development program
  - Estimate which controls will be needed and are most effective to attain air quality goals to the year 2000

The approach used in the NO_x E/A to address these needs gives primary emphasis early in the program to assessing current and impending control applications. Assessment of advanced technology applications will proceed at a lower level of effort early in the program but will be emphasized toward the end of the program. During the program, separate process engineering/environmental assessment reports will be generated for each major equipment category. These reports will focus mainly on current technology since it is more timely from an environmental standpoint and since it has been more extensively tested. The final report will document the assessment of far-term applications and will update the earlier assessments of near-term applications.

To support this approach, preliminary priorities are needed for:

- The sequence in which the major source categories are to be assessed and the level of effort devoted to each
- The near-term source/control applications to be assessed
- The source/control combinations to be addressed in the assessment of far-term applications, e.g., those likely to see application in this century

- The effluent stream/pollutant combinations to be emphasized in the test programs and assessments

In this report the preliminary source/control screening is conducted independently of the pollutant screening. Initially the source/control combinations are screened on the basis of significant near-term or far-term application. Pollutants for the resultant source/control combinations are then screened for potential adverse impacts. The results are then combined to set program priorities.

The earlier sections of this report summarized most of the information required to determine these four priorities. This section consolidates that information and adds estimates of near- and far-term source/control requirements to attain and maintain air quality. The priorities were then set in the sequence of the above list. The criteria used are listed below; supporting sections are indicated in parentheses.

Source Priorities

- Current and projected use of specific equipment design/fuel combinations within a source category (Section 2)
- Extent of current or impending NO_x regulations for the source category (Section 4)
- Ranking of source NO_x emissions on a national basis (Section 5)
- Relative potential for adverse environmental impacts (Section 6)
- Current and projected effectiveness of the source in urban NO_x abatement (Section 7.1)

Near-Term Source/Control Priorities

- Extent of use and effectiveness of controls for the source category (Section 4)
- Near-term need for and effectiveness of specific source/control combinations in urban NO_x abatement (Section 7.1)

Far-Term Source/Control Priorities

- Trends in source use (Section 2)
- Developmental status and effectiveness of emerging technology (Section 4)
- Far-term need for specific source/control combinations in urban areas for various control strategy options (Section 7.1)

Effluent Stream/Pollutant/Impact Priorities

- Baseline uncontrolled emissions (Section 5)
- Incremental emissions due to NO_x controls (Section 6)
- Estimated limits on ambient pollutant concentrations (Section 3)

Where possible, these criteria were quantified. It was not attempted at this stage, however, to carry a rigorous quantification through to numerical weighting of priorities. This is because the combined effects of the general lack of data, the early stage of the program, and the general uncertainty in the national NO_x abatement strategy would make such an approach unproductive. The qualitative priorities that are set will be updated and reevaluated as new data become available and results of supporting program tasks are completed.

Section 7.1 screens current and advanced combustion modification NO_x controls for effectiveness in attaining and maintaining the ambient NO_2 standard. This evaluation relates to the prioritization criteria listed above. These results, together with the results of previous sections are evaluated in Section 7.2 to arrive at preliminary source/control priorities for the near-term and far-term effort. Evaluation of potential pollutant/impacts for the near-term source/control combinations is given in Section 7.3. Section 7.4 summarizes the conclusions of the preliminary assesement.

7.1 EVALUATION OF NO_x CONTROL REQUIREMENTS

This section presents the methodology and results of a preliminary analysis to evaluate NO_x control requirements for the attainment and maintenance of the ambient NO_2 standard. The results of this analysis on two AQCRs will be used to identify the type and level of NO_x emission control necessary to meet the NO_2 ambient air goals. The main goal of this preliminary analysis is to set priorities for the NO_x E/A program. Therefore, only ambient NO_2 concentrations were considered under the assumption that their reductions are directly dependent on NO_x emission reductions. There is no attempt to consider either NO_x-HC or NO_2-oxidant interaction effects on the NO_2 concentration. These effects are considered to be beyond the scope of a preliminary analysis. Moreover, neglecting these effects is not expected to significantly alter the priorities based on this analysis.

A preliminary screening model forms the basis of the analysis. As described in Section 7.1.1, it processes the input data on emissions, ambient concentrations, and NO_x control to identify the most cost effective control strategy to attain and maintain the NO_2 ambient standard. The principal components of this systems model are the ranking of control methods and the air quality model, which for this preliminary analysis is a modified form of rollback. In Section 7.1.2 the procedure for selecting the two AQCRs is described. Los Angeles and Chicago were selected from a group of NO_2-critical AQCRs because they are already in violation of the NO_2 standard and they represent two contrasting NO_x problems — mobile source dominated and stationary source dominated. The input data for those two AQCRs are described in Section 7.1.3, and the results of the analysis are presented in Section 7.1.4. That section shows that maximum stationary source controls will be required if there is to be a reasonable chance of achieving the NO_2 standard in these two AQCRs.

7.1.1 Preliminary Screening Model

The preliminary screening model serves to coordinate the various elements that together form a cost effective control strategy for achieving the NO_2 ambient standard. The requirement of the model is that it provide a useful tool for relating emissions to ambient concentrations and for assessing the cost and effectiveness of controls for meeting the NO_2 standard. In this case the utility of the model is judged on the basis of:

- Simplicity of input
- Cost per solution
- Flexibility
- Relevance of results

The basic elements that must be incorporated into the model are:

- Calculation of emissions
- Calculation of fuel use
- Calculation of cost of control
- Ranking of controls for order of application to reduce source emissions
- Relationship of controlled emissions to ambient concentration

The first three elements listed above are solely of a "bookkeeping" nature, whereas the last two can range from very simple to very sophisticated models. This is especially true of the air quality model — the relationship between emissions and ambient concentration. A general discussion of air quality models and the choice of the model for use in the preliminary phases of the NO_x E/A program are presented in the following paragraphs. The other elements (auxiliary models) of the screening model are then briefly described in the remainder of this subsection.

7.1.1.1 Air Quality Models

An air quality model is any methodology for relating atmospheric contaminant concentration to pollutant source emissions. Models differ not only in their degree of sophistication but also in their resolution and versatility. Usually the sophisticated models require considerably more elaborate input data than the simpler models. Furthermore, since even they are based on approximate modeling of physical phenomena, such as atmospheric turbulence and chemical kinetics, they still require a significant calibration effort and considerable experience to use them intelligently. On the other hand, the lower-order models, which try to model the atmospheric processes in an integral manner, are based on certain correlations of the available data and lack the resolution of the sophisticated models.

The air quality model is the key element of the preliminary screening model. Therefore, careful attention has been given to the choice of the model. The following factors have been considered:

- The precision required for forecasting air quality impacts
- The time and resources appropriate to this effort
- The availability of the required meteorological and air quality data for the area of interest
- The availability of a suitable spatially distributed emissions inventory
- The physical size of the area under consideration and the time scale of interest

Since some degree of uncertainty is involved in utilizing any available model, disagreement exists over which approach is best.

Table 7-1 provides a summary of the basic model types currently available.* The key features of each class of models, their input data requirements, and comparative costs for a similar set of calculations are given. The diversity exhibited by these models lies not only in the basic assumptions of the formulation but also in the refinements, the expense to run, the applicable geographical and time scales, and the effort required to calibrate the models. For the purposes of the preliminary screening analysis the single most restrictive feature is the input data requirement.

The modified rollback model is a simple and inexpensive model to use and can be readily applied to assess different control technologies and strategies. This model does not effectively

---

*Table 7-1 was constructed from information provided by References 7-1, 7-2, and 7-3.

TABLE 7-1. SUMMARY OF AVAILABLE AIR QUALITY MODELS

Model	Type[a]	Averaging Time	Accuracy	Method	Input Requirements	Output	Secondary Pollutants	Cost[b] Not Including Inventory Preparation	Comments
Rollback	E	Variable	Generally fair to poor	Simple data correlation	Source emissions, base year concentration and emissions	Concentration	Appendix J, smog chamber results, historical correlation	$2K	(1) No meteorology; (2) No consideration of source distribution; (3) No consideration of chemistry; (4) Not extendable to rural areas; (5)Secondary pollutant calculations compound errors in primary; (6) Very simple, flexible, cheap; (7) Minimal input data requirements
Statistical Trajectory	E	1 hr	300%	Stat. fit to chem. Trace history of air mass prior to arrival	Surface wind vectors throughout area, gridded inventory	Concentration at 1 receptor station	Chemical correlation	$10K – $15K	(1) No vertical mixing; (2) May be useful for rural areas; (3) No consideration if elevated sources; (4) Empirical chemical correlations
Markov Chain	E	1 hr – 1 yr	20% for probability of exceedance	Statistical	Wind fields, gridded sources, extensive historical air quality data	Probability of exceeding some level in basin	Historical correlation	$25K – $35K	(1) Reduced sensitivity to specific sources via consideration of many, many trajectories; (2) Many runs are necessary; (3) Rural extensions questionable since no data base
Nonreactive Dispersion (CDM)	D/E	Variable	Fair to good	Gaussian plume nonreacting	Gridded sources, stack heights, joint frequency dist. for meteorology	Concentration contours for primary pollutant	Correlation, Appendix J, smog chamber	$10K – $15K	(1) Must relate empirical correlation of NO_2 precursor – may offset geographical advantages; (2) Can treat elevated sources; (3) Questionable on rural extension
Photochemical Box	D	1 hr	200%	• Fully mixed • Chem kinetics • Allows advection	Precursor conc., mix depth, temp. aggregate source inventory, HC inventory by class	Basin wide concentration	Direct. calculation	$25K – $50K	(1) No geographical differentiation; (2) May possibly be useful for rural; (3) Must have detailed HC inventory
Lagrangian Traject.	D	Up to 1 hr	30% – 40%	• Track air parcel • Chem kinetics • Vertical diffusion	Gridded inventory, RHC/NRHC, initial and boundary conditions, wind speed	Conc. history of 1 recepter, or conc. history of 1 air mass	Direct. calculation	$35K – $50K per receptor	(1) Can be applied to rural areas; (2) Can handle elevated sources; (3) Includes meteorology; (4) Must have detailed HC inventory; (5) Eulerian in vertical direction
Eulerian Photochem/ Diffusion	D	1 hr	20% O_3 40% NO_2	• Difference equations • Chem kinetics	Same as above	Air basin conc.	Direct. calculation	$150K – $200K	(1) See above 1-5
Multibox Eulerian	D	1 hr	30% O_3 50% NO_2	• See above • Integrate vert. direct.	Same as above	Air basin conc.	Direct. calculation	$60K – $80K	(1) See above 1-4; (2) Integral treatment of vertical profiles

[a] E – empirical; D – deterministic

[b] Costs – assumes that a suitable inventory is available. The cost of preparing this is quite variable and depends on what has already been done.

account for changes in distribution of emissions over time and space. Therefore, the accuracy of air quality estimates will suffer if the emission patterns are significantly altered. Moreover, the rollback model assumes that meteorology and the NO_x-HC and NO_2-oxidant interaction effects for the study area will be similar for the base year and future years.

The more complex models are designed to explicitly include the physical processes that relate emissions to ambient pollutant concentrations. As such, they are most applicable to significantly altering emission patterns and can be used to assess the impact on an air basin of selected control strategies. A wide variety of models with differing degrees of sophistication and applicability falls into this category. These models can be divided into two classes: nonreacting dispersion (Gaussian plume) and photochemical diffusion models. The former approximates the dispersion process by simple, experimentally based formulations, whereas the latter starts from the basic principles of conservation of mass and species and develops numerical solution procedures to account for transport, turbulent mixing and chemical reactions, especially photochemistry. These models require considerably more extensive input data, including spatial distribution of sources and meteorological variables, than does the rollback model.

Since the main purpose of the preliminary systems analysis is to assist in setting priorities for conducting detailed process engineering and environmental assessments of the possible source/control combinations, the model need only provide qualitative results on the cost effectiveness of the various control options. Furthermore, it should serve this function without excessive cost or undue effort in input preparation. Thus, the modified rollback model was selected rather than one of the more complex, and supposedly more accurate, models described in Table 7-1. The degree to which the well known shortcomings of rollback affect the results is variable, and in some cases rollback yields results that are in good agreement with even the most complex models. Furthermore, the impact of these shortcomings, or assumptions, on the results can be assessed by way of a sensitivity analysis, and this will be done in Sections 7.1.3.2 and 7.1.3.6. Although rollback was selected for use in the preliminary analysis, more complex models, especially ones that include the relationships between NO_x emissions and ozone, as well as other secondary pollutants, will be considered in later phases of the program.

The form of the rollback model used here is given by

$$AC = k\left(\sum_i (1 - R_i)\, E_i W_i\right) + BG \qquad (7\text{-}1)$$

where AC = ambient concentration

E_i = uncontrolled emissions from source i

R_i = reduction by control of source i

W_i = weighting factor for source i

BG = background concentration (the background concentration has been assumed to be 10 μg/m³ for all cases)

The calibration constant, k, is determined by evaluation of the equation at some "base year" for which the ambient concentration, emissions, etc., are known. Although parameters such as stack height and relative position of source and receptor are not explicitly reflected in the model, they are implicitly included because the model is essentially a correlation between existing emission patterns and the resulting ambient air conditions. Moreover, these two factors can be introduced by assigning proper values to the source weighting factors.

7.1.1.2 Auxiliary Models

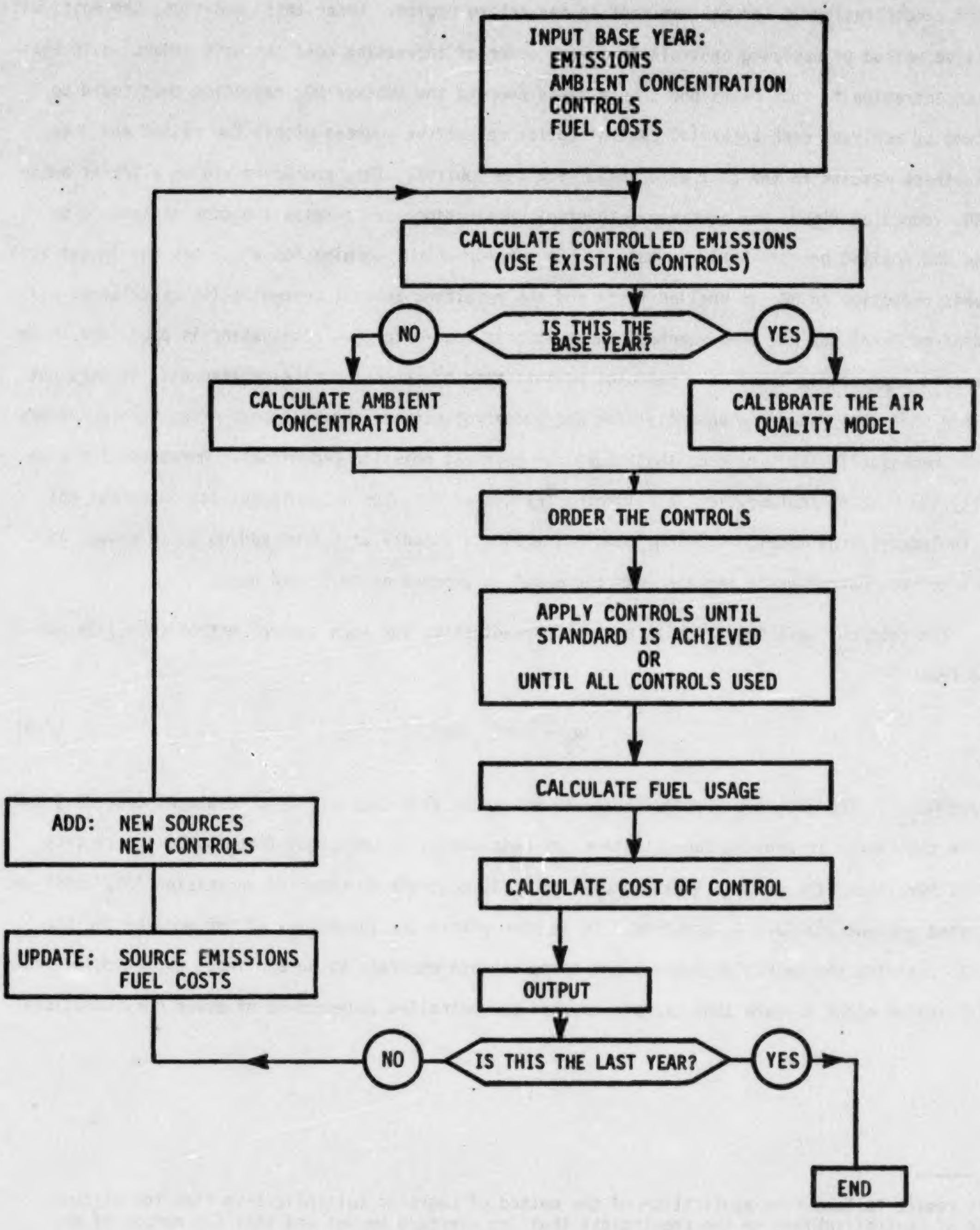
Preparation of the input to the air quality model and processing of the output are the functions of the various auxiliary models. Figure 7-1 shows the flow of information through the preliminary screening model. The functions of the various auxiliary models are described in the following paragraphs.

Emissions

The purpose of this portion of the model is to combine the effects of source growth, control, and weighting (relative impact of the source on the ambient concentration) to compute the net emissions from each source category for use in the air quality model. Uncontrolled emissions for the base year and each future year of interest are input for each source category. Controls to reduce the emissions are either input or prescribed by the model as necessary to achieve a preset ambient concentration. They are input, for example, when it is known that an emission standard will come into effect for a specific source at some future date. When the systems model* chooses the control, it selects from a table of options according to the algorithm (described below) used to set control priorities. In addition, provision has been made to weight the emissions from each source in a predetermined manner (see Section 7.1.3.6).

---

*Preliminary screening model and systems model are used interchangeably.



INPUT BASE YEAR: EMISSIONS AMBIENT CONCENTRATION CONTROLS FUEL COSTS
CALCULATE CONTROLLED EMISSIONS (USE EXISTING CONTROLS)
NO
IS THIS THE BASE YEAR?
YES
CALCULATE AMBIENT CONCENTRATION
CALIBRATE THE AIR QUALITY MODEL
ORDER THE CONTROLS
APPLY CONTROLS UNTIL STANDARD IS ACHIEVED OR UNTIL ALL CONTROLS USED
CALCULATE FUEL USAGE
ADD: NEW SOURCES NEW CONTROLS
CALCULATE COST OF CONTROL
UPDATE: SOURCE EMISSIONS FUEL COSTS
OUTPUT
NO
IS THIS THE LAST YEAR?
YES
END

Figure 7-1. Flow chart for the preliminary screening model.

Prioritization of Controls

In general, the goal of a regional air pollution control strategy is to achieve a specified ambient concentration at the minimum cost to the entire region. Under this condition, the most cost-effective method of applying controls is in the order of increasing cost per unit reduction in ambient concentration.* This means one should first compute the ambient NO_2 reduction that could be obtained by applying each potential control to its respective sources within the region and then relate these results to the cost associated with the control. This procedure yields a $/unit ambient NO_2 reduction figure for each source/control combination, and permits the combinations to be ranked and applied on this basis. That is, the source/control combination which has the lowest cost per unit reduction in NO_2 is applied first and the resulting ambient concentration calculated. If the desired level has not been reached, the next most cost-effective combination is used, and so on. Since this approach is based on a regional optimization of control cost effectiveness, it does not consider the total reduction potential for every control method; the most cost-effective approaches are not necessarily the same ones that cause the greatest emission reductions. Moreover, for simplicity the cost of implementing or enforcing any set of emission or equipment standards has not been included in the model. Nothing, however, prevents a model user from adding these costs, if known, to the control costs and allowing the model to proceed as described here.

The cost per unit reduction in ambient concentration for each control method (CUR_j) is computed from

$$CUR_j = CURE_{ij}/\Delta AC_i \tag{7-2}$$

where $CURE_{ij}$ is the cost per unit reduction in emissions from source i as a result of control j and ΔAC_i is the change in ambient concentration per unit change in emissions from source i. In this terminology, then, the program is structured to apply controls in order of increasing CUR_j until the specified ambient standard is achieved. It is also within the capability of the program for the user to override the selection process and force certain controls to be applied. For example, legislative action might dictate that certain sources be controlled independent of other considerations.

---

*This result follows from application of the method of Lagrange multipliers to find the minimum cost of control subject to the constraints that the standard be met and that the number of any particular control not exceed the number of sources to which it can be applied.

Fuel Use

This component of the systems model calculates the net fuel used (GJ/yr) for each fuel type. The base year fuel use, by fuel type, is input for each source. Fuel use is then assumed to grow at the same rate as uncontrolled emissions. Changes in fuel consumption can occur either from fuel switching or by a change in fuel consumption as a result of a control application. The net fuel use and net change in fuel use (for each fuel type) from the uncontrolled case are required in the cost-of-control calculation.

Cost of Control

The cost of each control method is composed of two parts — the incremental cost of fuel as a result of the application of the control and all other costs. These basic costs are input by the model user and include the annualized capital cost, maintenance and other operational costs. The incremental cost of fuel is treated separately to facilitate changes in projected fuel prices. This cost is calculated from the price of fuel and the changes in fuel consumption caused by the control method. Once a control strategy which achieves the desired ambient level has been identified, the two components of cost are summed for each control method used. These two costs and their sum, the net cost of control, are part of the model output.

7.1.2 Selection of the AQCRs

The United States and its territorial possessions are divided into 247 Air Quality Control Regions (AQCRs), largely for administrative reasons, to effectively manage the national effort to attain and maintain a clean environment. Although air pollution in each of these regions tends to be characterized by different combinations of emission sources and meteorological conditions, a preliminary analysis of NO_x control strategies for all the AQCRs is both impractical and unwarranted. This section, therefore, describes the methodology used to reduce the number of AQCRs under consideration by separating them into four groups, each with distinctive air pollution characteristics. Analysis of one member from each of the groups should be representative of the groups as a whole. For the purposes of the preliminary screening analysis only two of these representative AQCRs are considered.

The methodology can be summarized briefly as follows:

- Identify air pollution characteristics, including meteorology, emissions, ambient air quality levels, and data availability
- Group AQCRs according to their air pollution characteristics
- Select one AQCR to represent each group for further analysis

The details of each of these steps are presented in the following subsections.

7.1.2.1 Identification of Important Characteristics

One of the main purposes of the environmental assessment program is to identify those controls which are likely to be needed within at least some areas of the U.S. between now and the year 2000. Therefore, only those AQCRs which have, or are expected to have, a NO_x problem will be considered for analysis. These regions belong to one of the following two groups:

- Priority AQCRs — For the purpose of this study, regions will be classified Priority AQCRs if their ambient concentrations exceed the NO_2 standard when averaged over any consecutive four quarters (i.e., a rolling quarter basis rather than the statutory calendar year basis)
- AQMAs* — These are regions which have a high probability of exceeding the standard by 1985. Any region whose ambient NO_2 concentration lies between 80 and 99 $\mu g/m^3$, on a rolling quarter basis, will be considered an AQMA for NO_2.

The regions which fall into these two categories were identified by OAQPS (Reference 7-4) and are listed in Table 7-2. It is recognized that the "rolling-quarter" method will place more regions into the priority category; however, it has the advantage of providing a conservative approach to identifying potential problem areas. Moreover, it increases the number of regions for consideration (thus providing a more representative sample) and enhances the possibility of early identification of control technologies which may be required in the future. It is these potential control systems that are deserving of R&D to insure they are technically sound, cost- and energy-effective, and environmentally safe. The "rolling-quarter" approach is also consistent with advanced thinking in OAQPS, as witnessed by the listing in Table 7-2 that they supplied.

In order to divide the AQCRs in Table 7-2 into distinctive groups, the air pollution characteristics and emission properties described below must be considered.

Mobile Versus Stationary Sources

The distribution between mobile and stationary sources will be considered because it significantly affects the selection of a control strategy. The effectiveness of controlling any particular source depends, in part, on its total contribution to the problem. Thus, in a region like Los Angeles, where mobile sources account for approximately 66 percent of the total NO_x emissions, stationary source control, although necessary, will have less relative impact on ambient air quality than in a region like Detroit, which is dominated by NO_x emissions from stationary sources.

---

*AQMA — Air Quality Maintenance Area

TABLE 7-2. NO_x IMPACTED AQCRs AND AQMAs (ROLLING QUARTERS AVERAGE)

AQCR Number	City Name	Concentration ($\mu g/m^3$)
024	Los Angeles	182
067	Chicago	121
045	Philadelphia	121
174	Canton, Ohio	120
029	San Diego	119
115	Baltimore	116
123	Detroit	115
220	Salt Lake City	114
042	Springfield	113
043	New York City	113
036	Denver	110
225	Richmond	103
015	Phoenix	101
030	San Francisco	101
119	Boston	100
056	Atlanta	100
197	Pittsburgh	98
181	Steubenville	98
078	Louisville	96
178	Youngstown	96
122	Lansing	90
173	Dayton	90
070	St. Louis	85
234	Charleston, W. Va.	85
131	Minneapolis	84
079	Cincinnati	83
106	New Orleans	83
018	Memphis	81
239	Milwaukee	81
047	Washington, D.C.	80

Dominant Fuel Type

The fuel type from which the majority of stationary source NO_x comes should be considered in a grouping strategy. The type of fuel used in stationary source combustion constrains the effectiveness and choice of control options. For example, NO_x emissions from coal-fired utility boilers are not reduced significantly by FGR, whereas this technique is effective on gas- and oil-fired boilers.

Stationary Source Type

Stationary combustion sources can be divided into the following categories:

- Utility boilers
- Industrial boilers
- Commercial/institutional boilers
- Residential boilers and furnaces
- Internal combustion devices

The mix of sources within an AQCR is important because the type of control technology and its potential for reducing emissions are heavily dependent on the source type.

Ratio of HC Emissions to NO_x emissions (HC/NO_x Ratio)

This ratio is important because it controls the conversion of NO_x to oxidant. Therefore, the appropriate control strategy for oxidants depends on the ambient levels of these two pollutants. If the HC/NO_x ratio is high, the optimal control strategy relies on NO_x reductions, whereas if the ratio is low (a common situation in many cities), the strategy emphasizes HC reductions, at least for central urban areas. This ratio may, however, be of less importance in assessing R&D requirements because current thinking is that both NO_x and HC emissions must be reduced to simultaneously limit central urban and downwind oxidant levels.

Ambient Oxidant and NO_x Levels

These two quantities indicate the severity of the pollution problem. Also, if these do not correlate well with NO_x emissions it may indicate that the pollution problem is transported in from an adjacent AQCR. In this case an effective air quality program will require a multi-AQCR strategy.

Solar Insolation

Solar energy is an important factor causing temperature gradients and wind fields which give rise to mixing and turbulent diffusion. In addition, sun light is a key ingredient in the $NO\text{-}NO_2\text{-}O_3\text{-}HC$ interaction.

Stability Class

Stability classes are a function of wind speed and solar insolation. They reflect the mechanical turbulence or mixing in the atmosphere, an important factor in pollutant diffusion and transport. The EPA Star Program (Reference 7-9) lists Gifford-Pasquill stability class information as a bivariate frequency distribution of wind direction and wind speed. Stability classes are presented as:

- A — Extremely stable
- B — Unstable
- C — Slightly stable
- D — Neutral
- E — Stable

Quality of Data

A significant feature of any analysis is the quality of the input data. The complex air quality models described in Section 7.1.1 require extremely detailed gridded inventories of NO_x and RHC* emissions. A rollback model requires much less detail in the data. The Aerometric and Emissions Reporting System (AEROS) (Reference 7-10), was established by the EPA to be a source of this data. At this time the data in the AEROS system are not of sufficient quality to be solely relied upon. For rollback modeling the deficiencies can usually be overcome (see Section 7.1.3.1). However, the complex models require much greater accuracy if they are to be properly utilized. Data of this quality have been prepared for some AQCRs, and their availability will be an important factor in the selection of an AQCR for detailed study.

7.1.2.2 AQCR Groups

Data for each of the properties described above are shown in Table 7-3. Some of these data are more useful than others in grouping the AQCRs. For example, over 90 percent of the AQCRs are characterized by Stability Class D, so, this property is not a useful criterion. The ozone measurements recorded over a 2-year period show order of magnitude variations and are also of questionable value. Most of the remaining data originate from the AEROS data bank, are of satisfactory quality, and were given further consideration.

Three unsuccessful attempts were made to divide the AQCRs into distinctive groupings. The first sought a relationship between high mobile emissions and high HC/NO_x ratios; the second a correspondence between a high HC/NO_x ratio, a high ozone level, and a high solar insolation level; and

---

*RHC — Reactive hydrocarbons

TABLE 7-3. AIR POLLUTION CHARACTERISTICS OF THE NO_x IMPACTED AQCRs AND AQMAs

T-1578

City	AQCR Number	Mobile Stationary[a] (%)	Dominant Fuel[b] (%)	Stationary Combustion[c] (%)	Gifford Pasquill Stability Class[d]	HC/NO_x Ratio	NO_2 ($\mu g/m^3$)	1 Hour O_3[e] ($\mu g/m^3$)	Solar Insolation[f]
Los Angeles	24	66.0-M	38-G	72. -U	45%-D	1.649	182	376	H
Chicago	67	63.9-S	42-C	56. -U	58%-E	1.071	121	193	L
Philadelphia	45	54.8-S	53-O	55.6-U	—	1.142	121	157	L
Canton	174	56.4-S	80-C	55.6-U	—	1.438	120	95	L
San Diego	29	70.1-M	54-G	78.4-U	46%-D	1.678	119	189	H
Baltimore	115	58.9-M	61-O	63.9-U	49%-D	1.805	116	66	M
Detroit	123	52.5-S	62-C	65. -U	66%-D	1.340	115	115	L
Salt Lake City	220	54.3-M	33-G	58.7-I	48%-D	0.917	114	99	M
Springfield	42	54.0-M	66-O	55.3-U	—	1.308	113	341	L
New York City	43	61.2-S	82-O	56.3-U	51%-D	0.975	113	211	L
Denver	36	54.3-M	58-C	45.3-I	41%-D	0.987	110	176	M
Richmond	225	66.0-S	62-O	68.8-U	46%-D	0.917	103	181	M
Phoenix	15	76.1-M	70-G	72.7-U	46%-E	1.604	101	117	H
San Francisco	30	70.4-M	42-O	43.5-U	56%-D	1.471	101	163	M
Boston	119	53.5-S	94-O	48.6-U	70%-D	1.348	100	175	L
Atlanta	56	55.2-M	52-C	77.0-U	46%-D	1.122	100	157	M
Louisville	78	78.9-S	85-C	80.6-U	51%-D	0.843	96	122	M
St. Louis	70	75.0-S	72-C	88.3-U	57%-D	0.615	85	250	M
Cincinnati	79	56.8-S	79-C	69.9-U	—	0.972	83	118	M
Lansing	122	64.3-S	47-C	95.3-I	—	0.966	90	—	L
Dayton	173	57.3-M	67-C	51.9-U	57%-D	1.373	90	226	L
New Orleans	106	77.0-S	54-G	67.0-I	39%-D	1.171	83	136	M
Minneapolis	131	57.5-S	55-C	75.4-U	59%-D	0.632	84	190	M
Steubenville	181	90.1-S	63-C	62.8-U	—	0.139	98	107	L
Memphis	18	58.2-S	64-C	77.4-U	47%-D	0.801	81	—	M
Charleston, W. Va.	234	88.4-S	95-C	94.7-U	48%-D	0.199	85	127	M
Milwaukee	239	53.3-S	63-C	69.5-U	65%-D	2.519	81	—	L
Washington, D.C.	47	55.0-M	48-O	71.5-U	51%-D	1.052	80	180	M
Pittsburgh	197	77.1-S	90-C	83.4-U	66%-D	0.416	98	199	L
Youngstown	178	53.6-S	77-C	63.6-U	63%-D	0.855	96	226	L

[a] M — Mobile
S — Stationary

[b] Dominant source of NO_x by fuel type, % of stationary source NO_x emissions
G — Natural Gas
O — Oil
C — Coal

[c] U — Utility
I — Industrial

[d] These values represent the percent occurrence of the dominant stability class within each AQCR.

[e] Basin average of 99 percentile measurements

[f] Average daily solar insolation:
$H \geq 16.7\ MJ/m^2$
$M \geq 12.5\ MJ/m^2$
$L < 12.5\ MJ/m^2$

the third a relation between high mobile emissions and high ozone levels. None of these resulted in a significant degree of correlation. For example, ozone formation is not simply a function of solar insolation and HC/NO_x ratios; other influences on the ozone formation mechanism have to be considered. However, a reasonable set of groupings was obtained when the regions were separated into four groups as shown in Table 7-4. The major criteria for this grouping are the mobile/stationary source mix, the major stationary source type (utility or industrial), and the major fuel type for NO_x emissions. It should be noted that all of these have direct bearing on the most suitable control methods for effectively reducing NO_x emissions.

Group 1 represents regions that are dominated by stationary sources, with utilities as the largest NO_x emitters within the stationary category. Oil-fueled sources account for the greatest portion of the stationary source emissions. This group is associated with high NO_x levels, high HC/NO_x levels, and moderate ozone levels.

Group 2 is also dominated by stationary sources with utilities as the largest stationary source, but here coal-fueled sources are the dominant emitters of NO_x. These regions show moderate NO_x levels, medium HC/NO_x ratios and relatively low ozone levels.

Group 3 is similar to group 2 except that these AQCRs have high NO_x levels and high HC/NO_x ratios.

Finally, Group 4 is dominated by mobile sources. These regions are characterized by high NO_x levels, high HC/NO_x ratios, and very high ozone levels. The ozone levels are not unexpected, as mobile source emissions usually contain high concentrations of precursors for photochemical smog.

7.1.2.3 Selection of the Regions

One region is selected to represent each of the four groups. The choice is primarily dependent upon how well the individual AQCR represents the group as a whole, and on the quality and availability of emissions and ambient concentration data. The four AQCRs are given below:

- Group 1 — New York City
- Group 2 — Saint Louis
- Group 3 — Chicago
- Group 4 — Los Angeles

For the preliminary screening of control technologies this group was further reduced to Los Angeles and Chicago. These are logical choices for a limited analysis; they are the two most NO_x

TABLE 7-4. CHARACTERISTIC GROUPS OF NO_x IMPACTED AQCRs and AQMAs

	NO_x[a]	HC/NO_x[b]	Ozone[c]
1. Stationary — Oil — Utility			
New York City	H	H	M
Richmond	H	H	L
Boston	H	H	L
Philadelphia	H	H	L
2. Stationary — Coal — Utility			
St. Louis	M	M	M
Louisville	M	M	L
Cincinnati	M	H	L
Minneapolis	M	M	L
Steubenville	M	L	L
Memphis	M	M	--
Charleston	M	L	L
Lansing[d]	M	H	--
Pittsburg	M	L	L
Youngstown	M	M	L
3. Stationary — Coal — Utility			
Chicago	H	H	L
Canton	H	H	L
Detroit	H	H	L
Milwaukee	M	H	--
4. Mobile			
Los Angeles	H	H	H
San Diego	H	H	L
Baltimore	H	H	L
Salt Lake City	H	H	L
Springfield	H	H	H
Denver	H	H	M
Phoenix	H	H	L
San Francisco	H	H	L
Atlanta	H	H	L
Dayton	H	H	M
Washington	H	H	L

[a] High: $NO_x \geq 100\ \mu g/m^3$; Medium: $NO_x < 100\ \mu g/m^3$.

[b] High: $HC/NO_x > 0.9$; Medium: $0.45 < HC/NO_x \leq 0.9$; Low: $HC/NO_x \leq 0.45$.

[c] High: $300 \leq \text{Ozone} < 400\ \mu g/m^3$; Medium: $200 \leq \text{Ozone} < 300\ \mu g/m^3$; Low: $100 \leq \text{Ozone} < 200\ \mu g/m^3$.

[d] Lansing is shown in Table 7-3 to be industrial dominated. Since no utility emissions were reported, it was decided to place Lansing in Group 2.

critical AQCRs in the United States (see Table 7-2), and they represent two opposite categories with respect to the impact of stationary source control strategies — mobile source dominated versus stationary source dominated. Saint Louis and New York City may be assessed in subsequent analyses.

7.1.3 Summary of Input Data and Evaluation Matrix

The various inputs to the systems analysis model for the two AQCRs are described in this section. They are grouped into the following categories:

- Base year NO_x emissions and fuel use
- Base year NO_2 ambient concentrations
- Future year growth projections
- Fuel costs
- Stationary source controls

The input data and a brief discussion of how the values were selected are given for each category. The section concludes with a description of the various scenarios which were investigated with the preliminary screening model.

7.1.3.1 Base Year NO_x Emissions and Fuel Use

The base year for all calculations was 1973, the most recent year for which complete emissions data are available from a variety of reference documents. Primary sources for fuel use and emissions data this year were the 1973 NEDS Annual Fuel Summary Report and the 1973 National Emission Report (Reference 7-15). Copies of the relevant data from these sources are included in Appendix B. As described below, these data were checked for consistency with each other and were compared with similar data from other sources (References 7-16 through 7-20).

Consistency was checked first by comparing the emissions and fuel use data from all the data sources. This check was made for each source category, e.g., oil-fired utility power plants. If any major discrepancy in emissions was found among the data sources, the fuel use data were compared and, upon acceptance, used with an assumed emission factor to calculate the emissions. For example, it is known that reported emissions associated with process gas are often in error by as much as an order of magnitude. This is due to the greatly varying heat content of the gas and the use of inappropriate emission factors. Therefore, all such emissions were checked for consistency. The NEDS fuel use and emissions information for electric utilities were also routinely checked against the FPC fuel use reports (Reference 7-18). This category is such a large contributor that it deserves a verification, especially when a simple one is available. Furthermore, since many power plants in the Los Angeles AQCR implemented some combustion modification (LEA or OSC) for NO_x control in 1973, emissions were calculated from FPC fuel use data and actual emission factors as reported in Reference 7-19.

All source categories were checked in a similar manner. If there were any remaining, unexplained discrepancies, the EPA Regional Office or appropriate Air Pollution Control District was contacted. By this procedure a reasonably consistent set of fuel use-emissions data was established for each AQCR.

The emission source categories were initially selected to be identical to those in the NEDS reports. Individual source categories are necessary in order to account for distinct growth patterns and reductions by control for each category. The NEDS categories were judged to be sufficient in all cases except industrial point source external combustion and electric generation point sources. In these cases, it was desirable to distinguish between various boiler sizes and types. Also, source categories with small emissions or for which little or no control information is available were often combined. The source categories and their 1973 emissions and fuel use are given in Table 7-5 for Los Angeles and Table 7-6 for Chicago.

7.1.3.2 Base Year NO_2 Ambient Concentration

Ambient concentrations for the base year were used to calibrate the air quality model. The calibration was then used to relate emissions to ambient concentration in all future year calculations. Since the NO_2 standard is based on the maximum observed annual average throughout the AQCR for any calendar year, it was deemed reasonable to use this value for the calibration. However, other averages, such as the rolling quarter average,* have also been suggested as a more representative basis for a standard. Maximum values of the 12-month average for the Los Angeles and Chicago AQCRs are given in Tables 7-7 and 7-8, respectively. These values are based on averages from one calendar year, several calendar years, or the largest rolling quarter average during a 3-year period. The range of values reflects changes in both emissions and meteorological conditions.

Another consideration in the selection of the ambient concentration for calibration of the model is that the meteorological conditions of the base year are "frozen" into the calibration. Although these conditions do not change much, on the average, over the 20-year periods being considered here, year-to-year fluctuations in weather can cause ambient concentrations to vary by as much

---

*The rolling quarter average is the 12-month average for any four consecutive quarters.

TABLE 7-5. 1973 NO_x EMISSIONS AND FUEL USE FOR LOS ANGELES, AQCR 024

Source	NO_x Emissions (NO_2 Basis)			Fuel Use (PJ/yr)		
	Gg/yr	Gg/yr	Percent	Oil	Natural Gas	Process Gas
Electric Utilities		79.455	14.8			
Peaking	0.462			0.0358	3.135	
<50 MW	3.529			13.87	4.949	
50 MW - 180 MW	11.308			41.23	37.11	
>180 MW	64.156			311.0	103.7	
Industrial		32.990	6.2			
IC Engines	14.796				9.357	
Ext. Comb. — Large	2.891			3.19	9.599	20.17
Ext. Comb. — Small	2.891			3.19	9.599	20.17
Area	12.412			8.48	45.93	
Industrial Process	34.505	34.505	6.4	3.147	18.64	
Commercial/Institutional	19.886	19.886	3.7	55.75	236.5	
Residential		12.512	2.3			
Furnaces	9.926				231.0	
Other	2.586				141.5	
Solid Waste/Misc.	3.758	3.758	0.7			
Mobile	353.112	353.112	65.9			
Total	536.237	536.237	100	439.9	850.9	40.34

Gg = 10^9 grams = 1.1023 x 10^3 tons

PJ = 10^{15} Joules = 0.947 x 10^{12} Btu

TABLE 7-6. 1973 NO_x EMISSIONS AND FUEL USE FOR CHICAGO, AQCR 067

Source	NO_x Emissions (NO_2 Basis)			Fuel Consumptions (PJ/yr)			
	Gg/yr	Gg/yr	Percent	Oil	Natural Gas	Coal	Process Gas
Electric Generation		188.83	28.65				
Coal Firing Boilers	167.73					357.34	
Oil Firing Boilers	12.28			33.54	13.50		
G.T. (Peaking Unit)	4.52			30.96			
Other Pt. Source	4.30						9.81
Industrial		136.78	20.75	93.49			
Watertube Boilers	84.59			28.63	45.92	49.11	249.84
Firetube Boilers	23.90			28.63	45.92		
Area and Other Pt. Sources	28.29			36.23	184.22	26.08	
Industrial Process	41.34	41.34	6.27	20.24	60.17	1.91	
Commercial/Institutional	21.39	21.39	3.25	75.04	132.98	5.43	
Residential		15.18	2.30				
Furnaces	13.51			36.39	278.16	15.19	
Other	1.67			12.79	97.74		
Solid Waste	6.33	6.33	0.96				
Mobile	249.21	249.21	37.82				
Total	659.06	659.06	100	395.94	858.61	455.1	259.65

Gg = 10^9 grams = 1.1023 x 10^3 tons

PJ = 10^{15} Joules = 0.947 x 10^{12} Btu

TABLE 7-7. MAXIMUM ANNUAL AVERAGE NO_2 CONCENTRATION, LOS ANGELES, AQCR 024

μg/m³	Method
150	Average for 1970-1974 (Reference 7-11)
141	Calendar Year 1974 (Reference 7-12)
132	Calendar Year 1973 (Reference 7-13)
182	Rolling Quarter 1972-1974 (Reference 7-14)

TABLE 7-8. MAXIMUM ANNUAL AVERAGE NO_2 CONCENTRATION, CHICAGO, AQCR 067

μg/m³	Method
118[a]	Calendar Year 1974 (Reference 7-12, 26 Observations)
121	Rolling Quarter 1972-1974 (Reference 7-14)
96[a]	Calendar Year 1974 (Reference 7-12, 8,283 Observations)
133	Max. of Calendar Year 1972-1974 (Reference 7-29)

[a] The highest valid value for any station in 1973 was 76 μg/m³ (Reference 7-14). The stations reported here did not have enough observations to be valid in 1973. However, they have retained their high levels in later years. These values for 1974 are therefore considered reasonable to use for 1973.

TABLE 7-9. ANNUAL AVERAGE NO_2 CONCENTRATION USED FOR MODEL CALIBRATION (μg/m³)

AQCR	Nominal	Alternate
Los Angeles 024	132	160
Chicago 067	96	120

as 20 percent, even though emission patterns remain the same. Changes in meteorological conditions could be partially accounted for by changing the calibration, which can be done easily by changing the base year ambient concentration. This was not deemed necessary, because a suitable range of ambient levels is provided by the various averages given in Tables 7-7 and 7-8.

Two values of the ambient concentration, given in Table 7-9, were selected for each AQCR. The nominal value was taken to be the 1973 calendar year average. The alternate value was selected to represent the opposite end of the range of values in Tables 7-7 and 7-8. Consideration of both values will account for alternate averaging methods and perhaps any meteorological differences. In this way the sensitivity of the results to the calibration of the model can be evaluated.

7.1.3.3 Future Year Growth Projections

Stationary Sources

The uncontrolled emissions for future years were projected from fuel use growth rates. The assumption was made that in the absence of any further controls, emissions from each source category would grow at the same rate as fuel use in that category. Growth rates for fuel use were taken from References 7-21 through 7-26. Generally, these growth rates apply to an end use sector (industrial, residential, etc.); however, in this case they were extended to apply to each source within the sector. Whenever possible, growth rates specific to the AQCR were used. In the absence of these rates, state, regional or national rates were used. In addition, the influence of population growth and any local limitations on new source growth were considered.

Two scenarios for each AQCR were used. The nominal case represents a moderately conservative growth influenced by conservation measures and rising energy costs. This case is considered to be the "most likely to occur" case. The alternate case represents a higher growth rate situation, which is closer to historical growth patterns. The growth rates used for the two AQCRs for the years 1985 and 2000 are discussed below.

The two basic sources of growth projections for the Chicago AQCR are the Ford Foundation energy study (Reference 7-23) and Federal Power Commission projections (Reference 7-24). The nominal growth case is similar to the "technical fix" case described in Reference 7-23. This case represents a conscious effort to improve energy efficiency, and a moderate dependence on nuclear power for electricity generation. The growth rates and total growth for the years 1985 and 2000 are given in Tables 7-10 and 7-11.

The high growth case for Chicago is similar to the "historical growth" case of Reference 7-23. The growth rates and total growth for 1985 and 2000 are given in Tables 7-10 and 7-11. In this case

TABLE 7-10. AVERAGE GROWTH RATES IN ANNUAL FUEL USE FOR STATIONARY SOURCES IN CHICAGO, AQCR 067

Sector	1973-1985 %/yr		1985-2000 %/yr	
	Nominal	High	Nominal	High
Electricity Generation	0[a]	1.8	1.5	3.7
Industrial	3.3	4.4	3.3	3.2
Commercial	2.9	2.8	1.5	0.8
Residential	-0.1	0.3	-1.3	0.2

[a] Growth in electrical demand is expected to be met by an increase in nuclear capacity for the short term.

TABLE 7-11. INCREASE IN FUEL USE IN FUTURE YEARS FOR CHICAGO, AQCR 067, 1973 BASE

Source Type	1973	1985		2000	
		Nominal	High	Nominal	High
Utility Boilers — Coal	1.0	1.034	1.104	1.379	2.228
Utility Boilers — Oil	1.0	0.959	1.891[a]	1.096	1.397
Peaking G.T.	1.0	1.0	1.0	1.0	1.0
Industrial	1.0	1.434	1.612	2.345	2.607
Commercial	1.0	1.371	1.355	1.710	1.532
Residential	1.0	0.989	1.032	0.828	1.063

[a] This large increase is contrary to the trend toward coal; however, oil is a small fraction of the utility fuel budget. Commonweath Edison confirmed their plans to build several new oil-fired power plants.

there is substantial growth in nuclear power* and an increasing trend toward electrification. In some cases, this trend will result in less fossil fuel consumption than in the nominal case.

The major sources of fuel use growth projections for the Los Angeles AQCR are References 7-21, 7-25, 7-26, and 7-27. In addition, the population growth of 1.1 percent/year and the New Source Review Rate, SCAPCD Rule 213, were considered. Rule 213, in particular, will severely limit the growth of NO_x emissions from industrial and utility point sources.†

Both the nominal and the high cases are composites of the scenarios described in the references given above. The nominal case is a reasonable blend of the "medium" type growth projections and the expected influence of local regulations. The high case tends to represent a high growth scenario with effective local regulation (Rule 213). The growth rates and net growth for the various source categories are given in Tables 7-12 and 7-13.

In most cases, it is not sufficient merely to account for the source growth since a new type of equipment with significantly different emission characteristics may become available. This possibility has been allowed for by identifying the year of introduction of the new equipment and the lifetime of the existing equipment. Starting from the year of introduction, existing equipment is retired at a constant rate over its lifetime, and new equipment is added to make up the difference between the overall source growth and the remaining old equipment. Figure 7-2 illustrates how a typical source is divided. Retirement rates used in this analysis are given in Table 7-14. The emission characteristics of the new equipment may be the same as the old, or they may be improved depending upon the level of control desired or required.

Mobile Sources

Emissions from mobile sources have been treated in a different manner than those from stationary sources. The primary reason is that a detailed investigation of mobile source control options is not of direct interest to this study. What is needed is the emissions contribution of the mobile sources for a few representative scenarios. One scenario has been selected to reflect historical growth in vehicle population and miles traveled and a moderate emission standard. This is taken as the nominal case. The alternate, or low, case is for a reduced growth rate, closer to the population growth rate, and an emission standard of 0.25 g/km.

---

*The national growth in nuclear power given in Reference 7-23 is considerably modified by FPC projections in the Chicago AQCR.

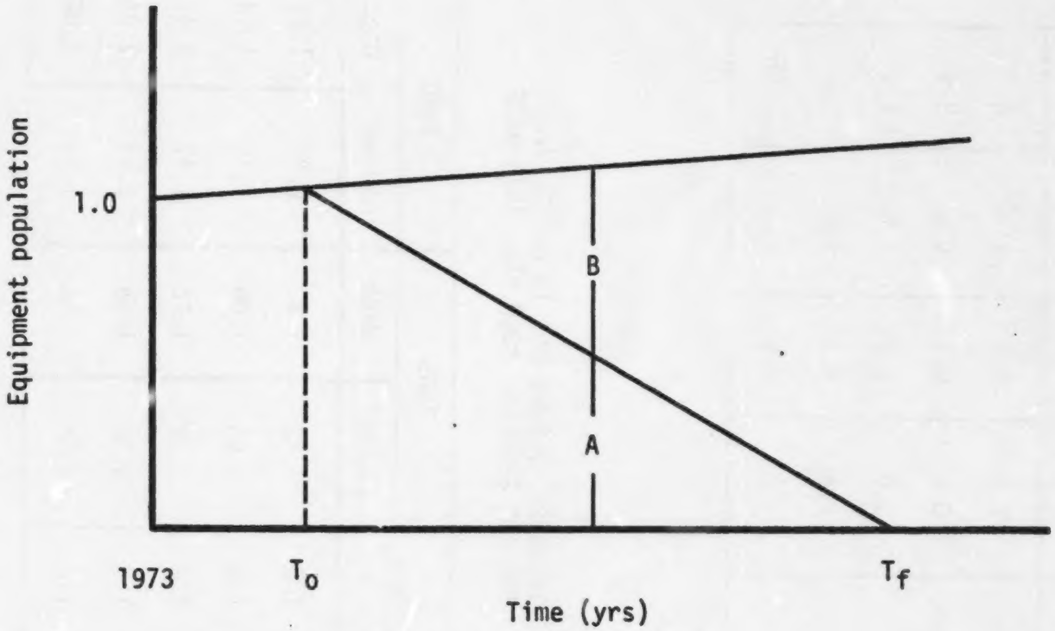
†In effect this rule would prohibit an increase in basin-wide NO_x emissions from specified source categories.

TABLE 7-12. AVERAGE GROWTH RATES IN ANNUAL FUEL USE FOR STATIONARY SOURCES IN LOS ANGELES, AQCR 024

Source	1973-1985 %/yr		1985-2000 %/yr	
	Nominal	High	Nominal	High
Utility — Oil	1.0	1.7	-1.35	0
Utility Peaking	0.5	0.5	0.5	0.5
Industrial	2.0	2.0	1.0	1.0
Commercial	2.6	4.3	3.0	3.9
Residential	1.2	2.6	0.3	2.65

TABLE 7-13. INCREASE IN FUEL USE IN FUTURE YEARS FOR LOS ANGELES, AQCR 024; 1973 BASE

Source Type	1973	1985		2000	
		Nominal	High	Nominal	High
Utility Oil	1.0	1.12	1.22	0.92	1.22
Utility Peaking	1.0	1.06	1.06	1.14	1.14
Industrial	1.0	1.26	1.26	1.47	1.47
Commercial	1.0	1.36	1.66	2.12	2.94
Residential	1.0	1.16	1.36	1.21	2.02



T_o = year of introduction of new equipment type
T_f = T_o + equipment lifetime
A = portion of source that is old equipment
B = portion of source that is new equipment

Figure 7-2. Distribution of a source into new and old equipment.

TABLE 7-14. EQUIPMENT RETIREMENT RATES

Equipment Type	Life Time (yr)	Retirement Rate %/yr
Utility Boilers	50	2.0
Large Industrial Boilers	35	2.9
Small Industrial Boilers	33	3.0
Commercial Boilers	33	3.0
IC Engines	50	2.0
Small Commercial Furnaces — Oil	25	4.0
Residential Furnaces — Oil	25	4.0
Residential Furnaces — Gas	20	5.0
Small Commercial — Gas	20	5.0

A description of both scenarios for the two AQCRs is given in Table 7-15. The emission standard and year of introduction, and the annual growth for the categories considered are shown. The emission standards for Chicago are representative of federal standards. Those for Los Angeles reflect the current and proposed standards for California.

The mobile source emissions for both scenarios and both AQCRs are given in Table 7-16. Details of how the standards and growth rates were used to calculate annual emissions are given in Appendix C. For vehicles, the following factors were considered:

- Number of vehicles
- Age distribution
- Average miles traveled
- Emission factor by model year

In addition, the emission factors were adjusted for deterioration with age and for average trip speed. (It is interesting to note the increasing significance of the "other" category. Much of this is from rail, ships, construction vehicles, and other off-road vehicles. It is often argued that these emissions do not significantly contribute to urban air quality.)

7.1.3.4 Fuel Costs

Part of the cost of many controls is the increase or decrease in fuel use as a result of implementing the control method. Therefore, current and projected fuel costs must be input into the program. Fuel costs for 1973 were obtained primarily from FEA (Reference 7-22) and FPC News (Reference 7-28). Cost projections to 1985 are based on the "$13/bbl reference case" of Reference 7-22. Beyond 1985 fuel cost projections are very uncertain. It may be expected that the relative cost of energy will continue to increase; however, government price controls could stabilize the cost. Therefore, fuel prices in the year 2000 were assumed equal to the 1985 price with two exceptions. In Los Angeles, the price of industrial natural gas was increased to equal that of industrial oil. In Chicago, the price of industrial oil was increased to equal that of industrial coal. Both of these "equalizations" were done to remove a cost advantage of the "limited" fuel. Fuel costs are given in Tables 7-17 and 7-18 in 1976 dollars.

7.1.3.5 NO_x Controls and Control Costs

This subsection summarizes the data on NO_x control techniques and control costs which are input to the preliminary screening model. For each equipment/fuel combination, an existing or emerging

TABLE 7-15. MOBILE SOURCE EMISSION FACTORS (g/km) AND ANNUAL GROWTH RATES

	Nominal					Low					Both Cases/Both AQCRs		
	LDV[c]		LDT[c]		Aircraft[b]	LDV[c]		LDT[c]		Aircraft[b]			
	Calif[a]	Fed	Calif	Fed		Calif	Fed	Calif	Fed		HDG[c]	HDD[c]	Rail, ships, etc.
<1972	2.9	2.9	2.9	2.9	No regulation	2.9	2.9	2.9	2.9	No regulation	11.7	27.4	No regulation
1972	1.9	2.9	1.9	2.9		1.9	2.9	1.9	2.9		11.7	27.4	
1973	1.9	1.9	1.9	1.9		1.9	1.9	1.9	1.9		11.7	22.8	
1974	1.2	1.9	1.2	1.9		1.2	1.9	1.2	1.9		11.7	22.8	
1975	1.2	1.9	1.2	1.9		1.2	1.9	1.2	1.9		7.0	13.7	
1977	0.93	1.2	1.2	1.2		0.93	1.2	0.93	1.2		5	9.8	
1978	0.93	0.93	1.2	1.2		0.93	0.93	0.93	0.93		↓	↓	
1980	0.62	0.62	0.93	0.93		0.62	0.62	0.62	0.62				
1981	↓	↓	0.62	0.62	.30 Reduction	0.25	0.62	0.25	0.62				
1985			↓	↓		↓	0.25	↓	0.25	.30 Reduction			
1990					↓		↓		↓	.40 Reduction			
1995										.50 Reduction			
2000										↓			
Annual Growth Rate	3.5%				1%	1%				1%	1%	1%	1%

[a] Reference C-11

[b] Reference C-23

[c] LDV — light-duty vehicles, LDT — light duty trucks, HDG — heavy-duty gasoline, HDD — heavy-duty diesel.

TABLE 7-16. MOBILE SOURCE NO_x EMISSIONS (All Values in Gg/yr Expressed as NO_2)

	Los Angeles — AQCR 024					Chicago — AQCR 069				
	1973	1985		2000		1973	1985		2000	
		Nominal	Low	Nominal	Low		Nominal	Low	Nominal	Low
LDV	224.0	84.5	40.2	121.0	24.9	155.0	61.0	44.6	81.4	17.0
LDT	27.7	12.9	5.6	13.6	2.8	6.7	3.9	1.8	3.9	0.6
HDG	20.2	12.2	12.2	8.8	8.8	12.2	7.3	7.3	5.2	5.2
HDD	25.3	9.6	9.6	9.2	9.2	26.5	10.0	10.0	9.6	9.6
Aircraft	4.8	3.8	3.7	4.4	3.1	35.9	28.5	28.3	32.8	23.5
Other	51.6	59.8	59.8	69.5	69.5	13.4	15.1	15.1	17.6	17.6
Total	353.6	182.8	131.2	226.5	118.3	249.7	125.8	107.1	150.5	73.5

TABLE 7-17. FUEL COSTS IN THE CHICAGO AQCR, 1973-2000

Fuel Costs	Fuel Costs ($/GJ)[a]		
	1973	1985	2000
Utility			
Coal	0.77	0.93	0.93
Oil	1.38	1.55	1.55
Natural Gas	1.01	3.96	3.96
Industrial			
Coal	0.83	1.40	1.40
Oil	0.87	0.96	1.40
Natural Gas	2.39	4.05	4.05
Process Gas[b]	0.87	0.96	1.40
Commercial			
Coal	1.36	2.00	2.00
Oil	2.34	2.64	2.64
Natural Gas	1.15	2.18	2.18
Residential			
Coal	1.58	2.34	2.34
Oil	2.34	2.65	2.65
Natural Gas	1.42	2.41	2.41

[a] Fuel costs are in 1976 dollars.

[b] The cost of industrial process gas was arbitrarily set equal to the cost of industrial oil.

TABLE 7-18. FUEL COSTS IN THE LOS ANGELES AQCR, 1973-2000

Fuel Type	Fuel Costs ($/GJ)[a]		
	1973	1985	2000
Utility			
Low Sulfur Oil	2.49	2.81	2.81
Natural Gas	0.74	2.87	2.87
Industrial			
Oil	2.00	2.17	2.17
Natural Gas	0.77	1.21	1.21
Process Gas[b]	0.77	1.21	1.21
Commercial			
Oil	2.42	2.72	2.72
Natural Gas	1.14	2.39	2.39
Residential			
Natural Gas	1.36	2.50	2.50

[a] Fuel costs are 1976 dollars.

[b] The cost of industrial process gas was arbitrarily set equal to the cost of industrial natural gas.

control technology is identified as being capable of achieving a given NO_x emission level. In addition, the differential costs associated with the control technology are presented. For the most part, these data are compiled from the information in Section 4 of this report. As noted there, good, reliable cost data for many NO_x control techniques are not available. In those cases where this is so, best projected estimates are made based on the available data.

Control costs and other process data are presented in Tables 7-19 through 7-27 for the following equipment/fuel combinations:

- Coal-fired utility boilers (Table 7-19)
- Gas- and oil-fired utility boilers (Table 7-20)
- Coal-fired industrial watertube boilers (Table 7-21)
- Gas- and oil-fired industrial watertube boilers (Table 7-22)
- Gas- and oil-fired industrial firetube boilers (Table 7-23)
- Gas- and oil-fired residential furnaces (Table 7-24)
- Gas turbines (Table 7-25)
- IC engines (Table 7-26)
- Industrial process furnaces (Table 7-27)

It was assumed that most stationary combustion sources of NO_x can be divided into these categories (the exceptions number only a few). The data presented represent expected typical ranges or average values over the entire spectrum of firing types and sizes within each category.

For a given NO_x emission level, the tables present a single or combined control technique capable of achieving that level, taking into account effectiveness, cost, availability, applicability, and operational impact. Environmental problems, however, were not considered in arriving at these selections. In those cases where the "earliest year available" is blank, the technology is considered available now. The differential control costs are shown in terms of both initial investment and annual costs in 1976 dollars. The annual costs include the differential costs of capital, raw materials, maintenance, and utilities. However, they do not include the cost associated with a change in fuel consumption. The effect on fuel consumption is tabulated separately in each table in accordance with the earlier discussion on the cost model (see Subsection 7.1.1.2). Details on other cost assumptions are discussed in Section 4.

Two other NO_x control methods not mentioned in these tables are ammonia injection and oil denitrification. Ammonia injection is an emerging technology projected to be commercially available

TABLE 7-19. COST OF NO_x CONTROLS FOR COAL-FIRED UTILITY BOILERS[a]

New or Existing Equipment	Emission Level (ng/J)	Control Technique[b]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/kW)	Annual Cost ($/kW)	
Existing[c]	344	LEA	--	0.6	0.1	<1% decrease
	301	LEA + OSC	--	1-1.5	0.2-0.3	<1% increase
New[d]	258	LEA + OSC	1982	0.2	<0.1	--
	215	Advanced Design 1	1984	0.5-1	0.1-0.2	--
	172	Advanced Design 2	1987	1-2	0.2-0.5	--
	129	Advanced Design 3	1990	2-7	0.5-1.2	--

[a] Ammonia injection may also be used with any of the combustion modification control methods. This results in an additional 50 percent reduction in NO_x emissions.

[b] See Section 4 for control technique characterization.

[c] The emissions level for existing uncontrolled units is assumed to be 387 ng/J.

[d] The emissions level for newly constructed units is assumed to be 301 ng/J.

TABLE 7-20. COST OF NO_x CONTROLS FOR GAS- AND OIL-FIRED UTILITY BOILERS[a]

New or Existing Equipment	Emission Level (ng/J)	Control Technique[b]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/kW)	Annual Cost ($/kW)	
Existing[c]	215	LEA	--	0.3	<0.1	<1% decrease
	143	LEA + OSC	--	0.5-1	0.1-0.2	1% increase
	107	LEA + OSC + FGR	--	6-12	1-2	1% increase
New	No new units					

[a] Ammonia injection may also be used with any of the combustion modification control methods. This results in an additional 50 percent reduction in NO_x emissions.

[b] See Section 4 for control technique characterization.

[c] The emissions level for existing uncontrolled units is assumed to be 258 ng/J.

TABLE 7-21. COST OF NO_x CONTROLS FOR COAL-FIRED INDUSTRIAL WATERTUBE BOILERS[a]

New or Existing Equipment	Emission Level (ng/J)	Control Technique[b]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/(kg/hr))[c]	Annual Cost ($/(kg/hr))[c]	
Existing[d]	193	LEA	--	22	4.9	1% decrease
	172	LEA + OSC	--	55	11.	<1% increase
New[d]	189	LEA	--	15	3.3	1% decrease
	163	LEA + OSC	1980	44	8.8	--
	129	Advanced Design	1985	110-176	22-35	--

[a] Ammonia injection may also be used with any of the combustion modification control methods. This results in an addition 50 percent reduction in NO_x emissions.

[b] See Section 4 for control technique characterization.

[c] kg/hr — kg steam per hour

[d] The uncontrolled emissions level is assumed to be 215 ng/J.

TABLE 7-22. COST OF NO_x CONTROLS FOR GAS- AND OIL-FIRED INDUSTRIAL WATERTUBE BOILERS[a]

New or Existing Equipment	Emission Level (ng/J)	Control Technique[b]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/(kg/hr))[c]	Annual Cost ($/(kg/hr))[c]	
Existing[d]	120	LEA	--	22	4.4	1% decrease
	108	LEA + OSC	--	44	8.8	<1% increase
New[d]	116	LEA	--	18	3.3	1% decrease
	103	LEA + OSC	1978	33	6.6	--
	86	Advanced Design 1	1981	55	11	--
	64	Advanced Design 2	1983	73	14.3	--
	43	Advanced Design 3	1985	88-154	18-31	--

[a] Ammonia injection may also be used with any of the combustion modification control methods. This results in an additional 50 percent reduction in NO_x emissions.

[b] See Section 4 for control technique characterization.

[c] kg/hr — kg steam per hour.

[d] The uncontrolled emissions level is assumed to be 129 ng/J.

TABLE 7-23. COST OF NO_x CONTROLS FOR GAS- AND OIL-FIRED INDUSTRIAL FIRETUBE BOILERS

New or Existing Equipment	Emission Level (ng/J)	Control Technique[a]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment (\$/(kg/hr))[b]	Annual Cost (\$/(kg/hr))[b]	
Existing[c]	108	LEA	--	0.66	0.13	1% decrease
	77	LEA + FGR	--	3.7	0.66	<1% increase
New[c]	108	LEA	--	0.44	0.09	1% decrease
	86	LEA + FGR	1978	1.59	0.31	--
	65	Advanced Design 1	1981	2.41	0.48	--
	43	Advanced Design 2	1985	3.3	0.66	--

[a] See Section 4 for control technique characterization.

[b] kg/hr — kg steam per hour.

[c] The uncontrolled emissions level is assumed to be 129 ng/J.

TABLE 7-24. COST OF NO_x CONTROLS FOR GAS- AND OIL-FIRED RESIDENTIAL FURNACES

New or Existing Equipment	Emission Level (ng/J)	Control Technique[a]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/kW)	Annual Cost ($/kW)	
Existing[b]	None					
New[b]	26	New Burner	1978	1.37-2.05	0.14-0.29	5% decrease
	17	Advanced Design 1	1981	2.05-3.42	0.29-0.4	7% decrease
	8.6	Advanced Design 2	1984	3.42-5.11	0.32-0.68	10% decrease

[a] See Section 4 for control technique characterization.

[b] The uncontrolled emissions level is assumed to be 43 ng/J.

TABLE 7-25. COST OF NO_x CONTROL FOR GAS TURBINES

New or Existing Equipment	Emission Level (ng/J)	Control Technique[a]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/kW)	Annual Cost ($/kW)	
Existing[b]	120	Water Injection	--	3-20	0.5-2	1% increase
New[b]	120	Water Injection	--	3-20	0.5-2	1% increase
	86	Advanced Design 1	1981	10-30	2-6	--
	43	Advanced Design 2	1984	20-50	4-10	--

[a] See Section 4 for control technique characterization.

[b] The uncontrolled emissions level is assumed to be 172 ng/J.

TABLE 7-26. COST OF NO_x CONTROLS FOR IC ENGINES

New or Existing Equipment	Emission Level (ng/J)	Control Technique[a]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/kW)	Annual Cost ($/kW)	
Existing[b]	1,053	Fine Tuning, Changing A/F	--	--	0.67-2.01	10% increase
New[b]	1,338	Fine Tuning, Changing A/F	1980	--	0.54-1.30	5% - 10% increase
	737	Advanced Design	1983	13.40-26.80	2.70-5.40	--

[a] See Section 4 for control technique characterization.

[b] The uncontrolled emissions level is assumed to be 1,504 ng/J.

TABLE 7-27. COST OF NO_x CONTROLS FOR INDUSTRIAL PROCESS FURNACES

New or Existing Equipment	Emission Level (ng/J)	Control Technique[a]	Earliest Year Available	Differential Control Costs		Effect on Fuel Consumption
				Initial Investment ($/kW)	Annual Cost ($/kW)	
Existing	258	LEA	--	1.01	0.22	1% decrease
	172	LEA + FGR	1978	5.80	1.01	1% increase
New	258	LEA	--	0.68	0.14	1% decrease
	129	Advanced Design 1	1981	3.74	0.76	--
	86	Advanced Design 2	1987	5.11	1.01	--

[a] See Section 4 for control technique characterization.

in the period 1981 through 1983. It is seen to have applicability to utility and large industrial watertube boilers with typical NO_x reductions of about 50 percent of the existing emission level. Annual costs have been estimated at \$5/kW to \$10/kW and 0.88 \$/(kg/hr)* to 1.98 \$/(kg/hr) for utility and industrial boilers, respectively. A major portion of these costs is the charge for ammonia. There seems to be no significant effect on fuel consumption.

Denitrification usually accompanies desulfurization of oil. The nitrogen content of the oil is reduced such that NO_x reductions of 10 to 40 percent from baseline can be achieved. Desulfurization typically adds \$0.8 to \$1.7 per barrel to the cost of residual or crude oil. Denitrification as a NO_x control method is applicable to residual oil-fired utility and large industrial boilers.

The annual control costs are given in terms of cost per unit output (8.9 \$/kW). In order to utilize these values in the systems analysis it is necessary to estimate the average unit size in each of the various source categories. The most effective procedure for doing this is to estimate an average annual capacity factor for each source type and combine this with the fuel use. This results in a total installed capacity for the particular source (total capacity = annual fuel use x annual capacity factor). From this the total cost to control the source can be calculated (example: total capacity in MW x \$/MW for the control method = total cost of the control method).

7.1.3.6 Evaluation Matrix

In order to adequately assess the level of emission reduction required to meet the NO_2 standard in 1985 and 2000 many combinations of the growth scenarios and base year calibrations could be considered. These combinations would all be derived from variations of the following four basic features:

- Stationary source growth rate
- Mobile source growth rate
- Values of the base year ambient concentration used for calibration of the air quality model
- Value of the source weighting factors for power plants and mobile sources

The first three of these have been discussed previously. The purpose of varying the source weighting factor is to evaluate the sensitivity of the results to the significance, or weighting, given to a particular source category. For example, it may be that because power plants emit from high stacks, a portion of their NO_x emissions does not contribute to the ambient NO_2 concentration in the AQCR. This may be due to transport out of the AQCR or different NO to NO_2 conversion rates for ground level and elevated sources. Therefore, it is of interest to examine what impact a reduction

---

[*] kg of steam per hour

in the significance of power plant emissions has on the results. Conversely, it has often been argued that mobile source emissions are a more significant contribution to high ambient NO_2 levels than other sources, since they emit both oxidant precursors (recall that NO_2 is formed from NO_x during the photochemical process) at the same elevation as the primary receptors. Therefore, the impact of increasing the significance of the mobile sources was also considered.

The evaluation matrix is a combination of two parts. The first part consists of the various combinations of growth scenarios for stationary and mobile sources and whether or not control of stationary sources is attempted. A description of each of these cases considered is given in Table 7-28. The same combination of scenarios was used for both Los Angeles and Chicago, and is considered to bracket all reasonable combinations of growth scenarios for mobile and stationary sources.

The second part of the evaluation matrix is formed from combinations of the base year ambient concentration and the source weighting factors. A change in the base year concentration is used to examine the sensitivity of the results to assumptions made in identifying this level. It also seems to show the sensitivity of the results to moderate changes in source-receptor spatial relations due to growth or the application of controls. This portion of the evaluation matrix is given in Tables 7-29 and 7-30. For each entry in these tables all the cases in Table 7-28 were evaluated. The results for this matrix of simulations for the years 1985 and 2000 are discussed in the following section.

7.1.4 Results

The preliminary screening model was utilized to compute ambient concentrations and required levels of control using the assumptions described in Section 7.1.3. The results of these calculations are presented and discussed in this section. Only a limited number of cases, selected as representative of the entire matrix of cases, will be described. The results are not intended to be predictions of future ambient concentration, because the limitations of the model and the uncertainty of the input data preclude such expectations. Rather, the results are indicative of the effectiveness of and the need for control of various sources.

Two types of results are described. The first is the ranking of the controls in order of cost-effectiveness. This is intended to provide guidance for the development of control methods and strategies. The second is an indication of the degree of control required to meet the annual standard. These results on the extent of control implementation to attain and maintain the standard are also compared with conclusions from similar studies.

TABLE 7-28. EVALUATION MATRIX, GROWTH SCENARIOS

A	Nominal growth for all sources Controls applied to meet std of 100 $\mu g/m^3$ in 1985, 2000
AN	Nominal growth for all sources No controls beyond those in use as of 1976
AM	Nominal growth for stationary sources Low growth mobile sources Controls applied to meet std of 100 $\mu g/m^3$ in 1985, 2000
AH	High growth for all stationary sources Nominal growth for mobile sources Controls applied to meet std of 100 $\mu g/m^3$ in 1985, 2000

TABLE 7-29. EVALUATION MATRIX: BASE YEAR CONCENTRATION AND SOURCE WEIGHTING FACTORS FOR LOS ANGELES

	Power Plant Weighting Factor[a]	Mobile Weighting Factor	Base Year (1973) Ambient Concentration
1	1.0	1.0	132
2	1.0	1.0	160
3	0.7	1.0	132
4	1.0	1.2	132
5	0.7	1.2	132
6	0.7	1.0	160
7	1.0	1.2	160
8	0.7	1.2	160

[a] For Los Angeles a power plant weighting factor of 0.7 was selected as a lower value for power plant sources. This was because the inversion layer above Los Angeles deflects emissions back into the air basin, thereby partially off-setting the effect of elevated sources. Thus, a significant reduction in weighting for power plant emissions would not be expected.

TABLE 7-30. EVALUATION MATRIX: BASE YEAR CONCENTRATIONS AND SOURCE WEIGHTING FACTORS FOR CHICAGO[a]

	Power Plant Weighting Factor	Mobile Weighting Factor	Base Year (1973) Ambient Concentration ($\mu g/m^3$)
1	1.0	1.0	96
2	1.0	1.2	96
3	0.5	1.2	96
4	0.2	1.0	96
5	1.0	1.0	120
6	1.0	1.2	120
7	0.5	1.2	120
8	0.2	1.0	120

[a] Dispersion of emissions from high stacks may have a very pronounced effect on the impact of elevated sources in the Chicago AQCR. For these sources Yeager (Reference 7-30) has suggested a source weighting factor of 0.356 as appropriate for nonreacting species for regions such as Chicago. Consequently, two reduced values of the power plant weighting factor were considered.

7.1.4.1 Ranking of Controls

The order in which controls are applied by the screening model is based on the cost per unit reduction in ambient concentration. As explained in Section 7.1.1 this approach allows for consideraion of the impact of each source/control combination on the ambient air quality. It differs, however, from the customary method of evaluating the cost-effectiveness of controls based on the reduction in emissions. For the air quality model used here, these two approaches yield the same result if all source weighting factors are equal. In the present analysis power plant weighting factors less than 1.0 and mobile source weighting factors greater than 1.0 are also considered. This has the effect of reducing the cost-effectiveness of power plant controls, i.e., the cost per unit reduction in ambient concentration increases. In both Los Angeles and Chicago this results in a moderate shift downward of the power plant control in the overall control ordering. Control rankings for Los Angeles and Chicago are given in Tables 7-31 and 7-32 for the year 2000 and for equal source weighting factors. Although the ranking is based on changes in ambient concentration the percent reduction listed for each control is the reduction of the uncontrolled emissions.* The controls have been divided into three groups according to their cost-effectiveness. Control levels will be described in terms of which group of controls is required to meet the ambient standard. Group I consists of all the controls that result in a net dollar savings. These include modifications to residential and small commercial furnaces and most low excess air controls. The net savings results from the decrease in fuel consumption associated with the control method. Group II contains the combustion modification controls that require hardware changes — off-stoichiometric combustion, flue gas recirculation, etc. In some cases these controls are applied in conjunction with some from Group I, e.g., low excess air plus off-stoichiometric combustion. The last set of controls, Group III, consists of the addition of ammonia injection to those controls in Group II for which this technique is applicable.

Tables 7-31 and 7-32 show that, with the exception of residential and small commercial furnaces, the maximum reduction in stationary source NO_x emissions by combustion modification is about 20 to 60 percent. The addition of ammonia injection increases this to 50 to 80 percent. It should also be noted that there are no controls for two potentially significant source categories — industrial processes and large commercial sources.† These were omitted primarily because of the extremely

---

*New equipment types with factory-installed NO_x controls are included as control methods. The cost associated with new equipment designs is that portion of the cost attributable to the NO_x control features (i.e., excludes R&D costs as these may be subtotaled in the estimate of the initial cost of the equipment).

†Commercial sources were divided into two groups — one that represents furnaces similar to residential furnaces, although larger; the other "large sources" consist of firetube boilers, large forced air heaters, and other miscellaneous types. For the purposes of control the latter group was considered too diverse to assign specific control methods.

TABLE 7-31. CONTROL PRIORITIZATION FOR LOS ANGELES (2000, EQUAL SOURCE WEIGHTING)

T-185

	Rank	Source/Control	Cost Per Unit Change in Air Quality $10^6\$/(\mu g/m^3)$	% Red/Unit
I	1	RES. FURN NEW BURNER	-15.4	40
	2	SM COMM FURN NEW D.	-14.6	40
	3	IND (WTB) LEA	-13.9	7
	4	SM COMM FURN A.D. #1	-12.7	60
	5	COMM/INST FURN A.D. #2	-13.3	80
	6	RES. FURN A.D. #1	-11.4	60
	7	RES. FURN A.D. #2	-11.3	80
	8	IND (FTB) LEA	- 3.67	17
II	9	SM PP LEA+OSC	1.57	45
	10	IC ENGINES ADJ A/F	2.18	30
	11	[a]MED PP TO 250 PPM	2.43	16
	12	IC ENG.-NEW ADJ A/F	2.48	11
	13	IC ENG.-NEW A.D.	0.305	51
	14	[a]LA PP TO 250 PPM	2.50	16
	15	SM PP LEA+OSC+FGR	2.74	58
	16	IC ENGINE-EGR	4.10	20
	17	[a]CCGT-NEW-H20 INJ	4.13	30
	18	CCGT-NEW A.D. #1	3.38	50
	19	CCGT-NEW A.D. #2	3.94	75
	20	IND (WTB) LEA+OSC	5.00	17
	21	IND (FTB) LEA+FGR	6.57	40
III	22	LA PP C.M.+NH3 INJ	6.74	79
	23	MED PP C.M.+NH3 INJ	7.59	79
	24	SM PP C.M.+NH3 INJ	8.25	79
	25	IND (WTB) C.M.+NH3	13.4	42

[a] Required to meet present legislated emission levels.

A.D. — Advanced design
C.M. — Combustion modifications (LEA, OSC, FGR)
COMM — Commercial
CCGT — Combined cycle gas turbine
EGR — Exhaust gas recirculation
FGR — Flue gas recirculation
FTB — Firetube boiler
FURN — Furnace
H20 INJ — Water injection
I, IND — Industrial
INST — Institutional
LA — Large
LEA — Low excess air
MED — Medium
OSC — Off-stoichiometric combustion
PP — Power plant
RES — Residential
SM — Small
WTB — Watertube boiler

TABLE 7-32. CONTROL PRIORITIZATION FOR CHICAGO (2000 EQUAL SOURCE WEIGHTING)

T-186a

	Rank	Source/Control	Cost Per Unit Change in Air Quality $10^6\$/(\mu g/m^3)$	% Red/Unit
I	1	RES. NEW BURNER	-43.8	40
	2	RES. FURN A.D.#1	-40.2	60
	3	RES. FURN A.D.#2	-38.3	80
	4	SM COMM FURN NEW D	-20.5	40
	5	SM COMM FURN A.D.#1	-18.6	60
	6	SM COMM FURN A.D.#2	-19.7	80
	7	IWTB-OIL LEA	- 3.98	6
	8	N IWTB-C LEA	- 3.47	12
	9	N IWTB-O LEA	- 2.94	10
	10	IWTB-COAL LEA	- 2.62	10
	11	PP-OIL LEA	- 0.923	16
	12	N IFTB-O LEA	- 0.673	17
	13	IFTB-OIL LEA	- 0.408	17
	14	PP-COAL LEA	- 0.397	11
II	15	N PP-C LEA+OSC 1982	0.294	14
	16	N PP-C A.D.#2 1987	0.335	43
	17	PP-COAL LEA+OSC	0.709	22
	18	N IFTB-O LEA+FGR	0.789	40
	19	N IWTB-O LEA+OSC	0.821	20
	20	N IWTB-O A.D.#2 1983	0.712	50
	21	N IWTB-C LEA+OSC	0.918	24
	22	N IFTB-O A.D.#2 1985	1.01	67
	23	PP-OIL LEA+OSC	1.04	45
	24	IWTB-COAL LEA+OSC	1.76	20
	25	N IWTB-C A.D.#1 1985	1.79	40
	26	IFTB-OIL LEA+FGR	1.94	40
	27	PP-OIL LEA+OSC+FGR	1.97	58
	28	IWTB-OIL LEA+OSC	2.39	17
III	29	IWTB-COAL C.M.+NH3	4.29	60
	30	PP-COAL C.M.+NH3	4.51	55
	31	N PP-C A.D.#2+NH3	4.56	71
	32	N IWTB-O A.D.#2+NH3	5.22	75
	33	PP-OIL C.M.+NH3	5.25	79
	34	N IWTB-C A.D.+NH3	6.14	70
	35	IWTB-OIL C.M.+NH3	6.46	58
	36	G.T. (PEAK) H2O INJ	11.16	30

N — New
C — Coal
O — Oil
A.D. — Advanced design
C.M. — Combustion modifications (LEA, OSC, FGR)
COMM — Commercial
CCGT — Combined cycle gas turbine
EGR — Exhaust gas recirculation
FGR — Flue gas recirculation
FTB — Firetube boiler
FURN — Furnace

H2O INJ — Water injection
I, IND — Industrial
INST — Institutional
LA — Large
LEA — Low excess air
MED — Medium
OSC — Off-stoichiometric combustion
PP — Power plant
RES — Residential
SM — Small
WTB — Watertube boiler

4118

diverse equipment types in these categories. Control costs and emission reduction information would be little more than guesswork. Certainly there is potential for reduction in both categories; however, omission of control methods did not have significant impact on the conclusions. To verify this, all the cases were run with a specified reduction in emissions from these two categories of 20 percent in 1985 and 60 percent in 2000. The result was to slightly decrease the control level necessary to meet the ambient standard. In most cases one or two fewer other sources required control.

In Tables 7-31 and 7-32 there are a few entries that appear to be out of order. For example, in Table 7-31 entry number 13 is more cost effective than the preceding entries. This is a consequence of the ranking process in the screening model. Second generation advanced designs of new equipment were forced to follow the new design in ranking. (In the example above, Entry 13 is the second generation advanced design for internal combustion engines.) This was done for two reasons. The first, and most obvious, is that the new design will be available before its own second generation and should therefore be given first consideration. The second is that the need for a second generation advanced design can be assessed independently of its relative cost advantage. If the new design did not provide sufficient reduction there would be some incentive to accelerate development of more advanced designs.

Figures 7-3 and 7-4 show the cumulative cost and reduction in ambient concentration resulting from the application of the controls in the order given in Tables 7-31 and 7-32 respectively. The location of most of the controls is indicated on the figures. The most striking feature of both figures is that the cumulative net cost for stationary control, up to ammonia injection, is negative. This result is heavily dependent upon the fuel savings or fuel penalties assigned to the control methods and upon the price of fuel. The major contributions (>60 percent) to the cost savings are the second generation advanced designs for residential and commercial furnaces (10 percent fuel savings). Without these two the break-even point occurs at a much lower level of control. This strongly suggests that the improved designs for these two sources should be vigorously promoted not only for the emission reduction but also for the significant fuel and cost savings potential.

Another interesting feature of these figures is that the total reduction in ambient concentration from all the controls is clearly evident. Those source/control combinations which have the

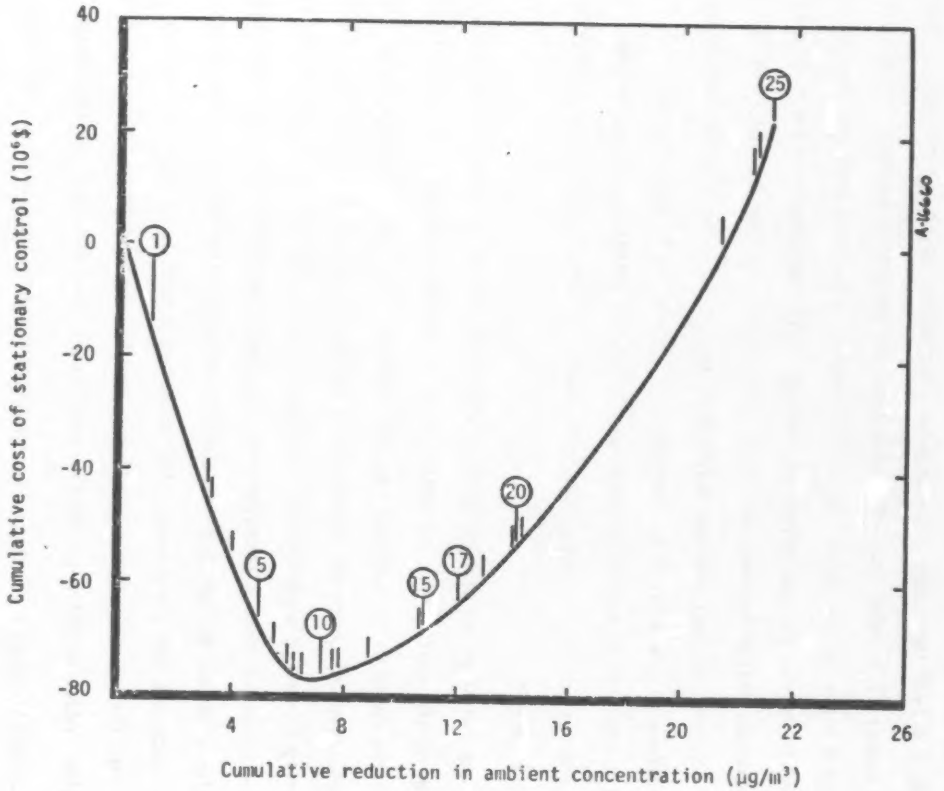


Figure 7-3. Cumulative cost and reduction in ambient concentration for application of the controls in Table 7-31 (preliminary process data, Los Angeles, 2000, nominal growth, 1973 concentration = 132 μg/m³).

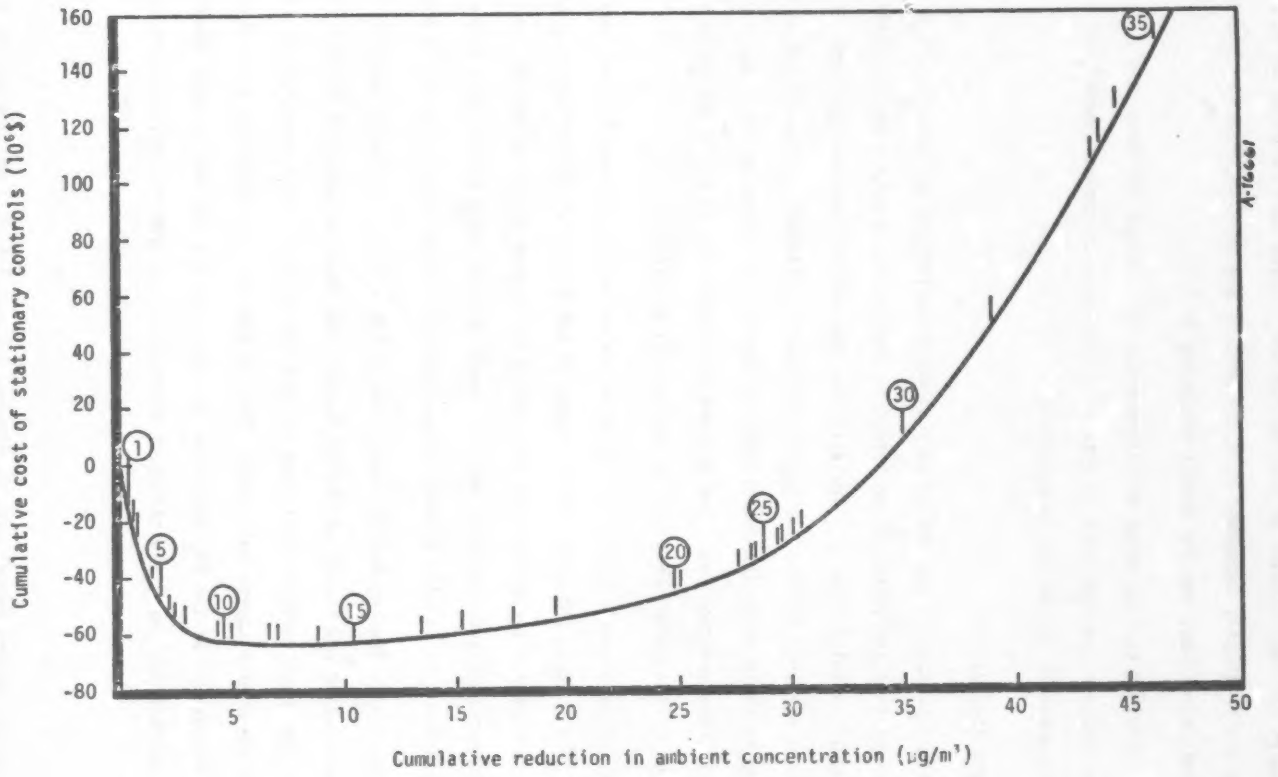


Figure 7-4. Cumulative cost and reduction in ambient concentration for application of the controls in Table 7-32 (preliminary process data, Chicago, 2000, nominal growth, 1973 concentration = 96 µg/m^3).

greatest reduction potential can be easily identified.* This information is more useful than cost effectiveness along in setting priorities for standards or control development.

The results and implications of Figures 7-3 and 7-4 are considered to be very tentative at this point and are critically dependent upon the process and cost information, the modeling assumptions, the growth scenarios, and the source weighting factors.

Control rankings such as those discussed above are created for each case of the evaluation matrix. These rankings are then used to establish the level of control needed for each case. These results are discussed in the following paragraphs.

7.1.4.2 Ambient Air Quality

The overall purpose of the preliminary screening effort is to identify the extent of combustion modifications that are likely to be needed in the future to attain and maintain NO_x-related ambient standards. Results from this analysis are, therefore, presented in terms of the general degree of control required to meet the annual average NO_2 standard. This method of presenting the results is used to avoid obscuring comparisons of the various cases by the details of exactly which control methods are required. The degrees of control (0, 1, 2, 3; see Table 7-33) are defined in terms of the groupings given in Tables 7-31 and 7-32.

Results for approximately half of the cases described in the previous section (Section 7.1.3) are presented here. These represent the extremes of the base year ambient concentrations, the two mobile growth and control scenarios, the two stationary source growth scenarios, and the case of reduced power plant impact and increased mobile impact. These cases effectively bound all the scenarios examined. Differences in results between these cases and those not discussed are minor.

The results for Los Angeles are given in Table 7-33. For each combination of growth scenario, base year concentration and source weighting factor, the required level of control for both 1985 and 2000 is shown. The most obvious conclusion is that the control level required is dominated by the assumptions on the mobile source emissions. This is not really surprising since mobile sources accounted for 66 percent of the NO_x emissions in 1973. In the low mobile case the combination of low growth (1 percent per year) and stringent controls (0.25 g/km in 1981) results in a 63 percent

---

[*] The distance along the horizontal axis in Figures 7-3 and 7-4 is a measure of the potential impact on ambient concentration of each control method. It is a combination of the total emissions contribution of the source and the effectiveness of the control method. In the case of combinations of controls (LEA+OSC) or improvements in design (second generation) only the additional improvement is credited to the method.

TABLE 7-33. SUMMARY OF CONTROL LEVELS REQUIRED TO MEET NO_2 STANDARD IN LOS ANGELES, AQCR 024

Case	BYR = 132 μg/m³		BYR = 160 μg/m³	
	PP = 1.0 MS = 1.0	PP = 0.7 MS = 1.2	PP = 1.0 MS = 1.0	PP = 0.7 MS = 1.2
Nominal Growth	1/3	0/3	3/V	3/V
Low Mobile	0/0	0/0	2/2	0/0
High Stationary	2/V	0/3	3/V	V/V

1985/2000

0 — No additional control required
1 — Controls from Group I
2 — Controls from Groups I and II
3 — Controls from Groups I, II, and III
V — Violation of NAAQS, insufficient controls to meet ambient standard

PP — Power plant weighting factor
MS — Mobile source weighting factor
BYR — Base year ambient concentration for calibration

reduction in mobile emissions in 1985 and a 66 percent reduction in 2000. This more than offsets the growth in stationary sources and results in a net reduction in total emissions of 36 percent and 38 percent respectively. This level of reduction is enough to achieve the ambient standard except in the 160 $\mu g/m^3$ base year case. Even in the nominal mobile case, a slight increase in the weighting of the mobile sources has significant impact in 1985.

In contrast to the low mobile cases, maximum control is needed for all other cases in 2000, and also for the high base year ambient concentration case in the near term (1985). Both of these are again consequences of the dominance of the mobile sources — control of the stationary sources cannot yield sufficient emission reduction to offset growth and the large mobile source emissions contribution.

These results strongly suggest that all possible stationary source control methods may have to be implemented. According to the results discussed above, which admittedly are based only on NO_2 ambient goals, a less vigorous approach could be justified only if all of the most favorable assumptions were valid (i.e., low base year concentration, low mobile growth, strict and effective mobile control, and validity of the higher mobile weighting assumption). It is unreasonable to expect that all of this will happen and imprudent to plan control development on such an assumption. For the short term the current combustion modification control technology might be sufficient if a favorable mobile situation exists. For the longer term, however, all the advanced control methods presently considered should be pursued, including ammonia injection, and research on even more effective methods seems justified.

The results for Chicago are shown in Table 7-34. Control of stationary sources is required in all cases except for 1985 if the base year (1973) concentration of 96 $\mu g/m^3$ is appropriate. The principal reason for this (no control in 1985) is that the reduction in mobile source emissions* counterbalances the growth in stationary sources. For example, in the nominal growth case, mobile source emissions in 1985 are 123 Gg below their 1973 level; whereas, stationary sources have increased by only 112 Gg. In the high stationary growth case, however, an increase of 154 Gg for stationary sources in 1985 is enough to require a small amount of control. Even with the low base year concentration the complete range of combustion modification controls is needed in the year 2000. For the high base year concentration cases combustion modifications and ammonia injection are not always sufficient, and even in the low mobile case combustion modification controls are needed.

---

*Mobile source emissions in 1985 are reduced by 50 and 57 percent of the 1973 level for the nominal and low mobile cases, respectively.

TABLE 7-34. SUMMARY OF CONTROL LEVELS REQUIRED TO MEET NO_2 STANDARD IN CHICAGO, AQCR 067

1985 / 2000

Case	BYR = 96 µg/m³			BYR = 120 µg/m³		
	PP = 1.0 MS = 1.0	PP = 0.5 MS = 1.2	PP = 0.2 MS = 1.0	PP = 1.0 MS = 1.0	PP = 0.5 MS = 1.2	PP = 0.2 MS = 1.0
Nominal Growth	0 / 2	0 / 2	0 / 3	3 / V	2 / V	3 / V
Low Mobile	0 / 2	0 / 2	0 / 2	2 / 3	2 / 3	2 / 3
High Stationary	1 / 3	0 / 3	0 / 3	3 / V	3 / V	V / V

0 — No additional control required
1 — Controls from Group I
2 — Controls from Groups I and II
3 — Controls from Groups I, II, and III
V — Violation of NAAQS, insufficient controls to meet ambient standard

PP — Power plant weighting factor
MS — Mobile source weighting factor
BYR — Base year ambient concentration for calibration

(The 1973 mobile emissions constitute 38 percent of the total; consequently, mobile emissions are not as dominant as in Los Angeles.)

The conclusions for the Chicago AQCR are essentially the same as for Los Angeles. For the long term all combustion modifications will be required and, in some cases, will not be sufficient to meet the annual standard. In the short term, combustion modifications are needed unless the low base year concentration is valid (see Section 7.1.3.2 for a discussion of this value).

These conclusions can be qualitatively extended to many of the AQCRs identified in Table 7-2 as Priority AQCRs and AQMAs. Those that are heavily mobile dominated (Group 4, Table 7-4) will respond to stationary source control in much the same manner as Los Angeles. It is quite likely that for these AQCRs, mobile source controls (0.63 g/km) would be sufficient for the short term; however, combustion modifications to stationary sources would be required in the long term. The stationary source dominated AQCRs, particularly those in the upper half of Table 7-2, will likely require combustion modifications, and perhaps ammonia injection, in both the near term and far term.

7.1.4.3 Comparison with Related Studies

The conclusions for the required control levels for both Los Angeles and Chicago are very similar to those of other studies, for example, the DOT study (Reference 7-29) and an EPA study (Reference 7-30). Both of these studies reported that neither Los Angeles nor Chicago could achieve the ambient standard with even maximum stationary source control and 0.25 g/km mobile controls. The results here indicate that it may be possible in favorable circumstances. The primary differences between the present analysis and the two cited above are in the growth rates and the base year ambient levels for which the models were calibrated. The DOT study allowed stationary sources to grow at 3.9 percent per year. The EPA study considered 5 percent per year growth and a base year concentration of 182 $\mu g/m^3$. Because of growth restrictions in Los Angeles (see Section 7.1.3.3), an effective annual growth of about 1 percent per year for the aggregate of the stationary sources was used in this work. In Chicago, electric power plant growth was much less than 3.9 percent, primarily because of growth in nuclear capacity. These factors account for the difference between never meeting the standard and possibly meeting the standard. These differences also help to illustrate the influence of the basic assumption (growth rate, base year concentration, and source weighting factors) on the quantitative results. However, the following qualitative conclusions remain the same.

7.1.4.4 Conclusions

The conclusions of this portion of the analysis can be summarized as follows:

- NO_x controls for residential furnaces and small commercial furnaces yield substantial reductions in fuel use and can significantly effect the break-even point in the cost for stationary source control strategies
- The order in which controls should be implemented is significantly influenced by the fuel savings features of the control method and, of course, the availability of the technology
- For the short term, combustion modifications for stationary sources will be needed for most of the priority AQCRs. Both retrofit and "new design" controls should be developed — particularly those that also result in an energy savings
- For the long term, all combustion modifications and ammonia injection will be required. This is probably the case even for the minimum mobile source emissions case (low growth, 0.25 g/km).

7.2 SUMMARY OF SOURCE/CONTROL PRIORITIES

This section combines the results of Section 7.1 with those of other sections to set NO_x E/A program priorities on sources and source/control combinations. The source priorities will be used to determine the order in which the process engineering and environmental assessment studies will be conducted for the major source categories (utility boilers, industrial and commercial boilers, gas turbines, commercial and residential warm air furnaces, IC engines and industrial process combustion equipment). The source priorities will also guide the level of effort to be devoted to the study of each major source category and to individual design types within the category. These studies will focus primarily on near-term source/control applications; far-term application of emerging technology will be studied later in the program. The source/control priorities will be used to determine which source/control combinations will be given major or minor emphasis in the near-term process studies and which will be emphasized in the far-term studies. The source/control priorities will also guide the field test program. Other factors such as site availability and the potential for teaming arrangements will also have a significant role in the test priorities.

The source prioritization used the following sequence:

- Subdivide major source categories (utility boilers) into source/fuel categories (coal-fired utility); further subdivide to major design types (tangential) likely to be extensively controlled for NO_x, and minor design types (vertical) not likely to be extensively controlled due to dwindling use and/or lack of control flexibility

- Assess the extent to which controls are in use or are planned for each source/fuel category
- Rank source/fuel categories on basis of nationwide mass emissions of NO_x
- Assess the relative baseline environmental impact potential for each source/fuel category
- Identify the relative effectiveness of near-term and far-term source control implementation in maintaining air quality in urban areas

Table 7-35 summarizes the results of this prioritization sequence. The prioritization is largely qualitative due to the uncertainty and lack of data in these areas. The considerations which were made in constructing Table 7-35 are summarized below.

Source Categorization

The division of the source/fuel category into major and minor design types used the results of Section 2 of this report. The major design types are those, which in the near-term, will be subject to NO_x controls. The designation "major" implies a design type will be given primary emphasis in the process studies and is a candidate for the field test program. The minor design types are either obsolete or difficult to control and therefore unlikely to be subject to significant NO_x controls. The minor design types will be given secondary emphasis in the process studies and will not be candidates for field tests. It should be noted that minor design types are not necessarily insignificant sources of NO_x. For example, cyclone boilers emit 8 percent of stationary source NO_x and rank fourth among all stationary source design/fuel combinations (see Table 5-33). Yet, the cyclone combustion characteristics make them very difficult to control for NO_x. Their sale has been discontinued and it is unlikely many existing units will be controlled for NO_x. Other considerations made in the source categorization are as follows:

- Vertical- and stoker-fired utility boilers are obsolete; although they are amenable to some control, the current application is insignificant
- Firebox and horizontal return tube package firetube boilers are dwindling in use in favor of the scotch design; the vast majority of new sales to meet the planned NO_x standard will be of the scotch design
- Firetube stokers are dwindling in number due to cost
- The use of NO_x controls on space heaters in the near term is unlikely
- Insufficient data are available to divide industrial process combustion equipment into major and minor design types

TABLE 7-35. EVALUATION OF NO_x E/A SOURCE PRIORITIES

T-250a

Source Category	Major Design Types[a] in E/A Program	Minor Design Types[a] in E/A Program	Degree of Control Implementation	Nationwide NO_x Emission Ranking	Relative Impact Potential[b]	Source Control Need/Effectiveness[b]		Source Ranking in E/A Program
						Near term	Far term	
Coal-fired utility	Tangential, single and opposed wall-fired, turbo	Cyclone, vertical, stoker	All new sources, moderate for existing sources	1	H	H	H	1
Oil-fired utility	Same as above	Cyclone	Extensive for existing sources	4	M	H	L	3
Gas-fired utility	Same as above		Same as above	3	L	H	L	8
Coal-fired watertube	Pulv. Stoker-spreader	Underfeed/ overfeed	Low for existing, impending for new	5	H	H	H	2
Oil-fired watertube	Single and multiburner		Same as above	10	M	H	H	6
Gas-fired watertube	Single and multiburner		Same as above	7	L	H	M-L	11
Coal-fired firetube		Stoker	Same as above	14	H	M	L	14
Oil-fired firetube	Scotch	Firebox, HRT	Same as above	6	M	H	H	5
Gas-fired firetube	Scotch	Firebox, HRT	Same as above	9	L	H	M-L	12
Gas- and oil-fired gas turbines	Industrial, utility, simple cycle	Comb. cycle repowering	Moderate for existing sources, impending for new sources	11	L	H	H-M	4
Gas- and oil-fired warm air furnaces	Res., Comm. furnace	Space heaters	Increasing use for energy conservation	12	L-M	H	H-M	7
Compression ignition IC engines (diesel fuel and mixed)	Turbocharged	Blower scavenged	Negligible for existing sources; impending for new sources	8	L-M	H	M-L	10
Spark ignition IC engines	Turbocharged naturally aspirated		Same as above	2	L-M	H	M	9
Industrial process combustion	Process heaters, furnaces, kilns		Negligible	13	M-H	M	M-H	13

[a] Major refers to sources likely to be controlled for NO_x; minor refers to sources for which controls are unlikely to be implemented in the near term.

[b] H = high; M = medium; L = low

The growth projection and design trends taken from Section 2 for this prioritization are preliminary. They will be studied in greater detail later and Table 7-35 will be updated as necessary.

Control Implementation

The information for the "Degree of Control Implementation" column on Table 7-35 is taken from Section 4.1. Since the assessment of current controls application is a major objective of the NO_x E/A, the degree of control implementation is a dominant criteria in setting source priorities. To date, the vast majority of stationary combustion source NO_x controls has been on utility boilers. Gas and oil units have been the most extensively controlled, but an increasing number of standards have been set recently for coal units. No new gas- or oil-fired units are being sold, so NO_x controls for coal units via the New Source Performance Standards (NSPS) will dominate in the future. Other sources with current control applications are large industrial boilers and gas turbines. NSPS are also planned for these sources along with IC engines. The lead time for implementing the standard and delivering new unit orders is typically several years. Thus, the degree of control application for these sources will not be comparable to that for utility boilers in the near term. This fact alone is sufficient to rank utility boilers as the top priority in the NO_x E/A.

Nationwide Emission Ranking

The ranking of design/fuel types by nationwide mass emissions of NO_x is given in Table 5-33. These results have been consolidated on Table 7-35 for the specific source categories listed there. Nationwide mass emissions are useful for weighting relative emission contributions of various sources and detecting emission trends independent of local variations. They are used within the EPA to set priorities on emission standards. Use of nationwide emissions does suffer a drawback, however, in that it does not account for variations among source categories in proximity to population centers and variations in regional use of specific source/fuel types. These factors were qualitatively included in the relative impact potential column. These factors will be quantified later in the NO_x E/A and used for a formal ranking of sources according to pollution potential.

Relative Impact Potential

The ranking of sources by relative impact potential was based on the multimedia emissions inventory of Section 5 and the evaluation in Section 7.3 of potential adverse impact of these emissions. Although impacts due to NO_x controls were not considered in the evaluation, the results of Section 6 were useful in relating design type and fuel to potential for emissions of specific pollutants (e.g., organic emissions from IC engines) where firm emission data were sparse. Additionally, the proximity of specified sources (e.g., residential furnaces) to populated areas was also considered. As shown on Table 7-35, the relative impact potential resulting from the above considerations was generally high for coal firing, medium for residual oil firing, and low with the firing of clean fuels. The borderline L-M for residential furnaces resulted from the proximity of these sources to populated areas and the potential for increased emissions during cycling transients. IC engines were also a borderline case. Even though they fire clean fuels, the emissions of organics are much higher than for other sources. Little emission/impact data are available for industrial process furnaces. They were rated M-H on the basis of fuel use.

Effectiveness of Source Control in Air Quality Maintenance

These criteria are based on the results of the air quality screening analysis discussed in Section 7.1. Separate consideration is given to near-term effectiveness and to far-term effectiveness in order to isolate effects of design trends and growth projections for source categories. The analysis in Section 7.1 showed that the need for bringing specific source categories under control is highly uncertain. The estimated control needs were found strongly dependent on growth projections, assumptions on future mobile source control, measurements of ambient concentrations of NO_2, and the relative weighting of the NO_2 air quality impact emissions from point sources (power plants) and ground level sources (mobile sources). These factors are all in a state of flux. Assuming optimistic resolution of these factors (in terms of stationary source air quality impact), only moderate control of major stationary sources will be needed in the near term (1985). Assuming moderate or pessimistic resolution of these factors, however, implies the need for extensive near-term control of stationary sources. In the far term (2000), extensive control is generally needed regardless of assumption. For purposes of setting priorities in the NO_x E/A program, the estimated control needs for moderate or pessimistic assumptions are used. This is because the NO_x E/A is largely a problem definition study and its purposes would not be served by using optimistic assumptions on the potential for adverse impact. For the moderate or worst case scenarios, the estimated near-term control needs, as shown on Table 7-35, are generally high for all source categories. For the far term, the needs are focused on extensive control of new sources. Thus, sources with dwindling new sales due to design trends or fuel availability are derated in the far term. As expected, the trend is for increasing use of coal and oil and decreasing use of gas. The projected availability of clean fuels for industrial sources and gas turbines will be examined in more detail later in the program.

Overall Source Ranking

The final column on Table 7-35 gives a qualitative ranking of the 13 source/control categories. In deciding this ranking, the degree of control implementation and the relative impact potential were given the most weight. Based on this ranking, the process and environmental assessment studies in the NO_x E/A will be conducted in the following sequence:

1. Utility and large industrial watertube boilers
2. Industrial and commercial packaged boilers
3. Gas turbines (simple cycle and combined cycle)
4. Residential and commercial warm air furnaces
5. Reciprocating internal combustion engines
6. Industrial process combustion equipment

Within each of these studies, the relative effort for specific source/fuel categories will follow the order of ranking of Table 7-35.

The source prioritization discussed above is extended on Table 7-36 to include consideration of specific source/control combinations. The table shows which source/control combinations are to receive major or minor emphasis in the six process studies of near-term applications listed above. The table also shows preliminary selection of which advanced source/control combinations will be evaluated in the later study of far-term applications. The prioritization of current technology was based directly on the information in Section 4 (see Tables 4-26 and 4-27). The prioritization considered the extent of current applications of specific source/control combinations and the cost effectiveness of a given control compared to competitive techniques. Major emphasis will be given to the vast majority of source/control combinations likely to see significant control in the next 5 years. The selection of advanced techniques for study in the far-term effort was also based on Section 4. The developmental status and schedule as well as the potential availability of competitive techniques were considered. The selection of advanced techniques also considered the results of Section 7.1 which showed the need for advanced combustion modifications and, possibly, ammonia injection in the 1980's and 1990's. Advanced techniques which are being covered by other assessment efforts (e.g., fluidized beds, advanced cycles) will be given minor emphasis in the far-term effort.

7.3 POLLUTANT/IMPACT SCREENING

The source/control combinations prioritized in Section 7.2 are further evaluated here to identify specific pollutants which may cause adverse environmental impact with or without NO_x controls. These results will be used to set priorities for the sampling and chemical analyses to be done during the later field test programs. The emphasis in the pollutant/impact screening is on flue gas emissions. The data on liquid and solid effluent streams are very sparse. They will

TABLE 7-36. SUMMARY OF NO$_x$ E/A SOURCE/CONTROL PRIORITIES

T-217

Source Ranking	Source	NEAR TERM EFFORT IN E/A PROGRAM: CURRENT AND IMPENDING APPLICATIONS				FAR TERM EFFORT IN E/A PROGRAM: ADVANCED TECHNOLOGY	
		Major Emphasis – Sources[a]	Major NO$_x$ E/A Emphasis – Controls[a]	Minor NO$_x$ E/A Emphasis – Sources[a]	Minor NO$_x$ E/A Emphasis – Controls[a,b]	Major Emphasis	Minor Emphasis
1	Coal-fired utility boilers, existing	Tangential, opposed & single wall, turbo-fired	LEA, BBF, BOOS, OFA, low-NO$_x$ burners	Cyclone, vertical stoker	FGR, RAP, H$_2$O inj., load reduction, NH$_3$ injection	NH$_3$ injection	
	Coal-fired utility boilers, new	Same as above	LEA & OFA; low-NO$_x$ burners, enlarged firebox		FGR, RAP, H$_2$O inj., NH$_3$ injection	Advanced OFA techniques; adv. low-NO$_x$ burners, NH$_3$ injection	Flue gas treatment; fluidized beds; adv. cycles
3, 8	Oil-fired, gas-fired utility boilers	Same as above	LEA, BBF, BOOS, OFA, FGR	Cyclone	RAP, H$_2$O inj., NH$_3$ injection	Advanced low-NO$_x$ burners, NH$_3$ inj.	Chemically active fluid bed
2	Coal-fired water-tube, industrial-pulverized	Single or multiburner wall-fired	LEA, BBF, BOOS, OFA, low-NO$_x$ burners		Load reduction	Advanced low-NO$_x$ burners, advanced OFA, NH$_3$ injection	
	Coal-fired water-tube industrial-stoker	Spreader	LEA, OFA	Underfeed/overfeed		Factory installed OFA, NH$_3$ inj.	
6, 11	Oil-fired, gas-fired watertube	Single or multiburner wall-fired	LEA, OFA, low-NO$_x$ burners		Load reduction	Adv. low-NO$_x$ burners, adv. OFA, NH$_3$ inj., alt. fuels	
14	Coal-fired fire-tube stoker			Firebox, horizontal return tube	LEA		
5, 12	Oil-fired, gas-fired firetube	Scotch	LEA, FGR, OFA, low-NO$_x$ burners	Firebox HRT	Load reduction	Adv. low-NO$_x$ burners, adv. OFA, alt. fuels, catalytic comb.	
4	Gas- & oil-fired gas turbines	Utility, industrial simple cycle	Water injection	Combined cycle, repowering	Can modifications	Adv. can design, comb. cycles, alt. fuels, catalytic comb.	
7	Gas- & oil-fired warm air furnace	Residential, commercial furnaces	Low-NO$_x$ burners	Space heaters		Adv. burner/firebox des., alt. fuels, catalytic comb.	
9	Spark ignition IC engines	Turbocharged, naturally aspirated	Operational tuning, reduced inlet air temperature		EGR, derate	Chamber redesign, alt. fuels	Exhaust gas treatment
10	Compression ignition IC engine (diesel, mixed fuel	Turbocharged	Operational tuning	Blower scavenged	Derate	Chamber redesign alt. fuels	
13	Industrial process combustion	Process heaters, furnaces, kilns	LEA, load reduction, RAP, FGR, H$_2$O injection	Low-NO$_x$ burners		Low-NO$_x$ burners, OFA, alt. fuels	

[a] Major refers to sources or controls emphasized in near term control programs; minor refers to sources or controls less likely to be used.

[b] LEA = low excess air; BBF = biased burner firing; BOOS = burners out of service; OFA = overfire air; FGR = flue gas recirculation; RAP = reduced air preheat

therefore be sampled during the test program to obtain the data needed for a pollutant/impact screening such as done here for flue gas emissions.

The set of pollutant classes under consideration was described in Section 6 and includes carbon monoxide, vapor phase hydrocarbons, particulates, sulfates, condensed phase organics, and trace metals. Several of these classes can be further speciated into more detailed pollutant groups, which give a better representation of potential health/welfare hazards, as was done in Section 3. For example, the vapor phase hydrocarbon class is comprised of alkanes, alkenes, alkynes, aldehydes, carboxylic acids, and aromatics. (Of course sulfates, organics, and trace metals are generally emitted as particulates, but the particulates class has been separately discussed because it is a criteria pollutant, and because more emissions data on this class of pollutants are available.)

Baseline emissions for each pollutant species group, as a function of combustion source class, were tabulated and discussed in Section 5. In addition, Section 6 tabulated (where data were available) and discussed the incremental emissions of these pollutant groups as a function of applied NO_x combustion control. The health and welfare aspects of each species/group were discussed in Section 3 in terms of developing a set of maximum ambient screening concentrations. By combining information developed in each of those sections with the dispersion model (which relates ground level pollutant concentrations to single source emission levels as a function of combustion source) described in Appendix D, it is possible to flag the pollutants from each combustion source which represent potential environmental hazards due to applying NO_x controls.

Such a summary appears in Tables 7-37 and 7-38. Table 7-37 shows baseline emissions, typical emission levels with NO_x controls, maximum ambient screening concentrations (from Section 3), and derived maximum allowable emission level (from the dispersion model) for the pollutant groups under consideration. The pollutant groups listed in Table 7-37 are those for which incremental emissions data are available. Table 7-38 shows a similar summary for those pollutants groups for which little or no field data exist on the incremental effects of NO_x combustion controls.

From the data presented in Tables 7-37 and 7-38, it is possible to identify those pollutant groups which are emitted at levels near, or exceeding, the defined maximum allowable emission level. For current purposes, pollutant group/combustion source combinations are flagged if emission levels with NO_x control data (Table 7-38), or baseline emissions in the absence of incremental NO_x control data (Table 7-38) exceed 10 percent of the maximum allowable level. These combinations are noted in Tables 7-37 and 7-38, and further summarized in Table 7-39.

TABLE 7-37. COMPARISON OF POLLUTANT EMISSION LEVELS WITH NO_x CONTROLS TO MAXIMUM ALLOWABLE EMISSIONS

T-215

Pollutant Class	Combustion Source	Fuel	Maximum Ambient Concentration (ppb)	Maximum Allowable Emission Level (ppm)	Baseline Emissions (ppm)	Emissions with NO_x Controls (ppm)	Concern Flag[a]
Carbon Monoxide			9,000				
	Utility Boilers	Natural Gas		110,000	23-175	25-65	
		Oil			25-46	10-35	
		Coal			23-96	20-148	
	Industrial Boilers	All Fuels		920,000	0-110	0-220	
	Residential Units	Natural Gas		529,000	40	--	
		Oil			90	--	
	IC Engines	All Fuels		920,000	90-10,300	90-3,280	
	Gas Turbines	All Fuels		920,000	53-970	51-1,320	
Total Vapor Phase Hydrocarbons			240				
	Utility Boilers	Natural Gas		2,930	0-35	0-40	
		Oil			0-30		
		Coal			0-40		
	Industrial Boilers	Natural Gas		24,500	10-25	0-35	
		Oil			0-15		
		Coal			10-90		
	Residential Units	Natural Gas		14,100	20	--	
		Oil			25	--	
	IC Engines	All Fuels		24,500	60-4,600	80-6,400	+
	Gas Turbines	All Fuels		24,500	0-230	0-1,200	
			(mg/m^3)	(g/m^3)	(g/m^3)	(g/m^3)	
Particulates			0.075				
	Utility Boilers	Natural Gas		0.91	0.01	--	
		Oil			0.11	--	
		Coal			0.42-2.73	0.60-2.6	++
	Industrial Boilers	Natural Gas		7.65	0.01	<0.03	
		Oil			0.01-0.63	0.02-1.23[b]	+
		Coal			3.9-5.1	7.5-10.0[b]	++
	Residential Units	Natural Gas		4.41	0.01	0.01	
		Oil			0.03	0.03	
	IC Engines	Oil		7.65	0.02-0.04	<0.26[c]	
	Gas Turbines	Oil, Kerosene		7.65	0.03-0.08	0.04-0.09[d]	

[a] + denotes emission with NO_x controls greater than 10 percent of maximum emission level.
++ denotes emission with NO_x controls greater than maximum emission level.

[b] NO_x control by off-stoichiometric combustion.

[c] NO_x control by exhaust gas recirculation.

[d] NO_x control by derating.

TABLE 7-38. COMPARISON OF BASELINE POLLUTANT EMISSION LEVELS TO MAXIMUM ALLOWABLE EMISSIONS

Pollutant Class/Group	Combustion Source	Fuel	Maximum Ambient Concentration (ppb)	Maximum Allowable Emission Level (ppm)	Baseline Emissions (ppm)	Concern Flag[a]
Vapor Phase Hydrocarbons[b]						
Alkanes			4,420			
	Utility Boilers	Natural Gas		54,000	<80	
		Oil			<15	
		Coal			<10	
	Industrial Boilers	Oil		450,000	<40	
		Coal			<150	
Alkenes			59,500			
	Utility Boilers	Natural Gas		725,000	<80	
		Oil			<15	
		Coal			<10	
	Industrial Boilers	Oil		Unlimited	<40	
		Coal			<150	
Alkynes			62,700			
	Utility Boilers	Natural Gas		765,000	<5	
		Oil			<5	
		Coal			<10	
	Industrial Boilers	Oil		Unlimited	<5	
		Coal			<10	
Aldehydes			2.1			
	Utility Boilers	Natural Gas		25.6	5	+
		Oil			5	+
		Coal			<10	+
	Industrial Boilers	Oil		214	2.5-200	++
Carboxylic Acids			13			
	Utility Boilers	Natural Gas		159	2.5	
		Oil			6-12	
		Coal			200	++
Aromatics (benzene and one-ring derivatives)			0.002			
	Utility Boilers	Natural Gas		0.024	<20	++
		Oil			<30	++
		Coal			<50	++
			(mg/m³)	(g/m³)	(g/m³)	
Sulfates			0.002			
	Utility Boilers	Natural Gas		0.024	0	
		Oil			0.047	++
		Coal			0.056	++
			(ppt)	(ppb)	(ppb)	
Organics (POM's)						
Anthracene			0.14			
	Utility Boilers	Coal		1.71	0.3	+
	Industrial Boilers	Oil		14.3	2	++
		Coal			0.1-0.3	
	Residential Units	Coal		8.2	0.4-1,000	++
Phenanthrene			4,000			
	Utility Boilers	Coal		50,000	0.1-0.3	
	Industrial Boilers	Natural Gas		420,000	0.04	
		Oil			0.7-3.7	
		Coal			0.3-3	
	Residential Units	Coal		240,000	9-2,300	

[a] + denotes baseline emissions exceed 10 percent of maximum allowable level
++ denotes baseline emissions exceed maximum allowable level

[b] Maximum ambient concentration and associated maximum allowable emission level for hydrocarbon species consider only primary health hazards. Effects of secondary (derived) pollutants are not considered.

TABLE 7-38. CONTINUED

T-216

Pollutant Class/Group	Combustion Source	Fuel	Maximum Ambient Concentration (ppt)	Maximum Allowable Emission Level (ppb)	Baseline Emissions (ppb)	Concern Flag[a]
Organics (POM's) (Cont.)						
Fluoranthrene			10,900			
	Utility Boilers	Coal		133,000	0.003-0.5	
	Industrial Boilers	Natural Gas		1,110,000	0.04-3.4	
		Oil			0.02-1.8	
		Coal			0.8-10	
	Residential Units	Coal		641,000	13-350	
Pyrene			0.121			
	Utility Boilers	Coal		1.48	0.01-0.5	+
	Industrial Boilers	Natural Gas		12.4	0.5-7.5	+
		Oil			0.005-2.2	+
		Coal			0.6-4.5	+
	Residential Units	Coal		7.1	2-2,500	++
Benzo(a)pyrene			0.097			
	Utility Boilers	Coal		1.2	0.003-0.1	
	Industrial Boilers	Natural Gas		9.9	0.006-0.1	
		Oil			0.006-0.3	
		Coal			0.007-2.2	+
	Residential Units	Coal		5.7	0.008-800	++
Benzo(e)pyrene			0.097			
	Utility Boilers	Coal		1.2	0.007-0.15	+
	Industrial Boilers	Natural Gas		9.9	0.006-0.5	
		Coal			0.02-1.7	+
	Residential Units	Coal		5.7	1-330	++
Perylene			0.097			
	Utility Boilers	Coal		1.2	0.005-0.015	
	Industrial Boilers	Coal		9.9	0.35	
	Residential Units	Coal		5.7	0.1-770	++
			$(\mu g/m^3)$	(mg/m^3)	(mg/m^3)	
Trace Metals						
As			0.825			
	Utility Boilers	Oil		10.1	0.004	
		Coal			0.45	
B			16.5			
		Oil		201	0.068	
		Coal			3.41	
Ba			0.825			
		Oil		10.1	0.52	
		Coal			0.65	
Be			0.0033			
		Coal		0.04	0.52	++
Bi			16			
		Coal		195	0.03	
Cd			0.00825			
		Oil		1.01	0.006	
		Coal			0.12	+
Co			0.165			
		Oil		2.0	0.27	+
		Coal			0.11	

[a] + denotes baseline emissions exceed 10 percent of maximum allowable level
++ denotes baseline emissions exceed maximum allowable level

TABLE 7-38. CONCLUDED

T-216

Pollutant Class/Group	Combustion Source	Fuel	Maximum Ambient Concentration (μg/m³)	Maximum Allowable Emission Level (mg/m³)	Baseline Emissions (mg/m³)	Concern Flag[a]
Trace Metals (Cont.)						
Cr			0.001			
	Utility Boilers	Oil		0.012	0.68	++
		Coal			0.43	++
Cu			1.65			
		Oil		20.1	0.55	
		Coal			1.20	
Hg			16.5			
		Oil		201	0.008	
		Coal			0.23	
Mn			8.25			
		Oil		101	0.55	
		Coal			1.58	
Mo			8.25			
		Oil		101	0.55	
		Coal			0.25	
Ni			0.165			
		Oil		2.0	32	++
		Coal			0.68	+
Pb			0.247			
		Oil		3.0	0.62	+
		Coal			0.59	+
Sb			0.825			
		Oil		10.1	0.004	
		Coal			0.04	
Se			0.33			
		Oil		4.0	0.632	
		Coal			0.173	
V			0.825			
		Oil		10.1	47.5	++
		Coal			1.20	++
Zn			1.65			
		Oil		20.1	0.87	
		Coal			9.36	+
Zr			8.2			
		Oil		100	0.17	
		Coal			0.86	

[a] + denotes baseline emissions exceed 10 percent of maximum allowable level
++ denotes baseline emissions exceed maximum allowable level

T-251

TABLE 7-39. SUMMARY OF POTENTIAL POLLUTANT/COMBUSTION SOURCE HAZARDS

Pollutant Class/Group	Combustion Source	Emission Exceeds Potential Hazard Threshold	Emission Exceeds 10% of Potential Hazard Threshold
Vapor Phase Hydrocarbons			
Total	IC Engines		X
Aldehydes	Utility Boilers, all Fuels		X
	Oil-Fired Industrial Boilers	X	
Carboxylic Acids	Coal-Fired Utility Boilers	X	
One-Ring Aromatics	Utility Boilers, all Fuels	X	
Particulates	Coal-Fired Boilers	X	
	Oil-Fired Industrial Boilers		X
Sulfates	Coal- and Oil-Fired Utility Boilers	X	
Organics			
Anthracene	Oil-Fired Boilers	X	
	Coal-Fired Residential Units	X	
	Coal-Fired Utility Boilers		X
Pyrene	Coal-Fired Residential Units	X	
	Boilers, all Fuels		X
Benzo(a)pyrene	Coal-Fired Residential Units	X	
	Coal-Fired Industrial Boilers		X
Benzo(e)pyrene	Coal-Fired Residential Units	X	
	Coal-Fired Boilers		X
Perylene	Coal-Fired Residential Units	X	
Trace Metals			
Be	Coal-Fired Utility Boilers	X	
Cd	Coal-Fired Utility Boilers		X
Co	Oil-Fired Utility Boilers		X
Cr	Coal- and Oil-Fired Utility Boilers		
Ni	Oil-Fired Utility Boilers	X	
	Coal-Fired Utility Boilers		X
Pb	Coal- and Oil-Fired Utility Boilers		X
V	Oil-Fired Utility Boilers	X	
	Coal-Fired Utility Boilers		X
Zn	Coal-Fired Utility Boilers		X

469

Table 7-39 illustrates that incremental emissions from large coal- and oil-fired boilers potentially represent most significant environmental hazards. Baseline emissions of particulate, sulfates, and certain POM species from this source class currently exceed the derived maximum allowable emissions levels, while emissions of several other POM species are within an order of magnitude of the maximum limit. In addition, while emissions of total vapor phase hydrocarbons from large boilers were not identified as being of concern, emissions of several hydrocarbon classes, notably oxygenates and aromatics, were flagged. Finally baseline emissions of several trace metals from coal- and oil-fired boilers were noted as exceeding, or falling within a factor of 10 of maximum levels. It is interesting to note that six of the eight flagged elements exhibit Class II, or segregating, behavior; they tend to repartition and concentrate in fine particulate.

Large coal- and oil-fired boilers were not the only source class associated with pollutant streams of concern. Incremental total vapor phase hydrocarbon emissions from IC engines operating with dry NO_x controls exceeded 10 percent of maximum allowable emissions and therefore represent another concern. In addition, baseline emissions of several organics from residential coal stokers exceeded maximum limits. However, the use of coal firing in residential heating applications is definitely declining, so this source/pollutant combination should not be considered a priority concern.

Based on the information presented in Table 7-9, it is clear that further study is needed of NO_x controls which could increase emissions of:

- Particulates from coal- and oil-fired boilers, e.g., off-stoichiometric combustion (OSC), flue gas recirculation (FGR), and ammonia injection (NH_3)
- Sulfates from coal- and oil-fired boilers, e.g., OSC, FGR, and NH_3
- Organics from coal- and oil-fired boilers, e.g., low excess air (LEA), OSC, and FGR
- Segregating trace metals from coal- and oil-fired boilers, e.g., LEA, OSC, and FGR
- Vapor phase hydrocarbons emissions from IC engines, e.g., all controls

7.4 FUTURE EFFORT

This report has:

1. Documented the scope of sources, pollutants, impacts and controls to be considered in the NO_x E/A
2. Evaluated data on impact criteria, control effectiveness, baseline multimedia emissions and incremental impacts of NO_x controls

3. Set preliminary priorities on source/control combinations and effluent stream/pollutants to be considered

These results will serve to initiate and scope the next efforts:

- Screen and rank the pollution impact potentials of uncontrolled sources and effluents (B1)
    - Update the Section 5 emissions inventory
    - Develop approach to assess emissions during nonstandard operation
    - Generate growth projections of source/fuel use and emissions
    - Expand impact analysis of Section 7.3
- Generate impact screening criteria for B1 and B5 assessments (B2)
    - Coordinate with other studies developing impact criteria; finalize human health impact criteria of Section 2
    - Decide approach to generalize terrestrial and aquatic impacts
    - Develop scenarios for alternate NO_2 air quality standards for the Task C air quality modeling
- Conduct field tests of priority source/control combinations (B3)
    - Survey candidate test sites for coal- and oil-fired utility and industrial boilers and oil-fired gas turbines using NO_x controls
    - Finalize sampling and analysis requirements based on the E/A steering committee recommendations and Section 7 results
- Generate process engineering and environmental assessment reports for utility boilers (B5)
    - Expand process data and control results of Sections 2 and 4
    - Develop cost model to standardize control cost estimates
- Develop systems analysis model with chemistry and dispersion effects (C)
    - Update model inputs with cost data from B5 and regional inventories from B1
    - Expand control assessment of Section 7.1 to consider NO_2-oxidant reactions and a short-term NO_2 standard

These efforts are discussed in the Preface and illustrated in Figure P-1.

The data evaluations contained in this report have shown the strong need for setting priorities in all areas of the program. Serious data gaps exist for baseline and controlled multimedia

471

emissions and impacts. These data gaps make it impossible to consider to a meaningful level all potential source/control/effluent stream/pollutant/impact combinations within the scope of the NO_x E/A. The program results will be most useful if the effort is prioritized to allow comprehensive assessment of fewer source-impact combinations. The prioritizations contained in this report have accordingly set the emphasis of the NO_x E/A as follows:

- Sources: Major emphasis on stationary fuel combustion sources firing coal or residual oil and projected to use a significant degree of NO_x controls in the near term; less emphasis on sources firing clean fuels; minor emphasis on sources which will not be controlled in the near term
- Controls: Major emphasis on most widely used current applications; less emphasis on advanced technology; minor emphasis on control techniques not widely used
- Effluent Streams and Pollutants: Major emphasis on flue gas emissions during steady-state operation; less emphasis on liquid and solid effluent streams; minor emphasis on emissions during transient or upset conditions
- Impacts: Major emphasis on human health impacts due to inhalation; less emphasis on terrestrial and aquatic impacts and on human health impacts due to ingestion via the food chain; minor emphasis on materials impacts

REFERENCES FOR SECTION 7

7-1. Eschenroeder, A., "An Assessment of Models for Predicting Air Quality," Environmental Research and Technology, Inc., ERTW-75-03.

7-2. "Air Quality Models Required Data Characterization," Science Applications, Inc., EPRI EC-131, May 1976.

7-3. Personal communication, Dr. Alan Eschenroeder, Environmental Research and Technology, Inc.

7-4. Personal communication, Mr. Alan Hoffman, Chief Monitoring Section, EPA, October 1, 1976.

7-5. AEROS — Emission Summary Report, Office of Air Quality Planning and Standards, U.S. EPA.

7-6. AEROS — Fuel Summary Report, Office of Air Quality Planning and Standards, U.S. EPA.

7-7. AEROS — National Emissions Summary Report, Office of Air Quality Planning and Standards, U.S. EPA.

7-8. "Climatic Atlas of the United States, 1974," U.S. Department of Commerce, Environmental Science Services Administration, Environmental Data Service.

7-9. Star Program, U.S. Department of Commerce, National Climatic Center, Asheville, North Carolina.

7-10. "AEROS Manual Series, Volume I: AEROS Overview," EPA-450/2-76-001, February 1976.

7-11. Trijonis, J. C., et al., "Emissions and Air Quality Trends in the South Coast Air Basin," EQL Memorandum No. 16, Environmental Quality Laboratory, California Institute of Technology, Pasadena, California, January 1976.

7-12. "Monitoring and Air Quality Trends Report," EPA-450/1-76-001, February 1976.

7-13. "Air Quality Data — 1973 Annual Statistics," EPA-450/2-74-015, November 1974.

7-14. Personal Communication, Ms. Pamela Henrichs, Ambient Air Monitoring Section, Division of Air Pollution Control, Illinois Environmental Protection Agency.

7-15. "1973 National Emissions Report, National Emissions Data System (NEDS) of the Aerometric and Emissions Reporting System (AEROS)," EPA-450/2-76-007, May 1976.

7-16. Babcock, L. R. and N. L. Nagda, "POPEX — Ranking Air Pollution Sources by Population Exposure," EPA-600/2-76-063, NTIS-PB 261 458/AS, March 1976.

7-17. "Fuel Use and Emissions from Stationary Combustion Sources," Southern California Air Pollution Control District, July 1976.

7-18. "Steam-Electric Plant Air and Water Quality Control Data for the Year Ended December 31, 1973," based on FPC Form No. 67 — Summary Report FPC-S-253, January 1976.

7-19. Bartz, D. R., et al., "Control of Oxides of Nitrogen from Stationary Sources in the South Coast Air Basin," KVB Report No. 5800-1795, ARB 2-1471, September 1974.

7-20. Personal communication, Mr. Robert Hilousky, Southern California Air Pollution Control District.

7-21. "Energy Alternatives for California: Paths to the Future," Rand Corporation, R-1793-CSA/RF, December 1975.

7-22. "National Energy Outlook — 1976," FEA/N-75/713, February 1976.

7-23. "A Time to Choose — America's Energy Future," Final Report by the Energy Policy Project of the Ford Foundation, 1974.

7-24. Personal communication, Mr. David Simon, FPC, Chicago Office.

7-25. Behrin, E. and R. L. Cooper, "California Energy Outlook," Lawrence Livermore Laboratory, UCRL-J1966, November 1975 (revised February 1976).

7-26. "Meeting California's Energy Requirements, 1975-2000," Stanford Research Institute, SRI Project ECC-2355, May 1973.

7-27. Personal communication, Mr. David Smith, Southern California Edison.

7-28. FPC News, Vol. 8, No. 13, March 28, 1975.

7-29. "Air Quality, Noise and Health," Interim Report, Interagency Task Force on Motor Vehicle Goals Beyond 1980, March 1976.

7-30. Yeager, Kurt, "The Effects of Desulfurization Methods on Ambient Air Quality," Advances in Chemistry Series 127, 1973.

APPENDIX A

EMISSION INVENTORY

Summary emission tables were presented in Section 5.4. A complete listing of emissions of the 29 pollutants considered for each equipment type, together with emission factors and NO_x control factors, is given in this appendix which has been subdivided into three parts.

A.1 NONCRITERIA POLLUTANT EMISSION FACTORS

Emission factors for noncriteria pollutants for utility boilers are presented in Tables A-1 and A-2. Factors for packaged boilers and warm air furnaces are in Tables A-3 and A-4, respectively. Trace element emissions were not computed for other equipment types, and no emission factors appear here.

A.2 FORMULATION OF NO_x EMISSION CONTROL FACTORS

Controlled NO_x emissions from a particular source type (A) firing a particular fuel (B) were calculated as

$$\text{Emissions} = \underbrace{(FC) \times (UEF) \sum_i fi \frac{EFi}{uEF}}_{\text{Term 1}} + \underbrace{(1 - \sum_i fi) \times (FC) \times (UEF)}_{\text{Term 2}} \qquad \text{(A-1)}$$

where

FC = total fuel consumption of fuel "B" in sources of the type "A"

UEF = uncontrolled emission factor for source/fuel "A/B"

fi = fraction of FC burned in controlled sources located in region "i"

EFi = regulated emission factor assuming 100 percent compliance for sources of type "A/B" in region "i" (EFi < UEF)

The first term is a sum over all regions "i" in which local control regulations demand an emission factor lower than the uncontrolled value. The second term accounts for the uncontrolled sources.

TABLE A-1. SECTOR I NONCRITERIA POLLUTANT EMISSION FACTORS

Equipment Type	Sulfates (ng/J)	POMs Low (pg/J)	POMs High (pg/J)	Dry Removal Ash (μg/J)[a]	Liquid Removal Ash (μg/J)[a]
Utility Boilers					
Tangential					
Anthracite	4.73	0.957	121.3	0.589	2.36
Bituminous	16.8	0.957	121.3	0.520	2.09
Lignite	3.01	0.957	121.3	0.37	1.46
Residual Oil	12.9	0.862	0.862		
Distillate Oil	3.01	0.862	0.862		
Natural Gas		0.313	27.48		
Single Wall-Fired					
Anthracite	4.73	0.398	121.3	0.589	2.36
Bituminous	16.8	0.398	121.3	0.520	2.09
Lignite	3.01	0.398	121.3	0.37	1.46
Residual Oil	12.9	0.862	0.862		
Distillate Oil	3.01	0.862	0.862		
Natural Gas		0.313	27.48		
Opposed Wall and Turbofurnace					
Anthracite	4.73	0.398	121.3	0.589	2.36
Bituminous	16.8	0.398	121.3	0.520	2.09
Lignite	3.01	0.398	121.3	0.370	1.46
Residual Oil	12.9	0.862	0.862		
Distillate Oil	3.01	0.862	0.862		
Natural Gas		0.313	27.48		
Cyclone					
Anthracite	4.73	1.84	1.84	0.589	2.36
Bituminous & Sub	16.8	1.84	1.84	0.520	2.09
Lignite	3.01	1.84	1.84	0.370	1.46
Residual Oil	12.9	0.862	0.862		
Distillate Oil	3.01	0.862	0.862		
Natural Gas		0.313	0.313		
Vertical & Stoker					
Anthracite	4.73	0.474	121.3	0.589	2.36
Bituminous & Sub	16.8	0.474	121.3	0.520	2.09
Lignite	3.01	0.474	121.3	0.37	1.46
Residual Oil	12.9	0.862	0.862		
Distillate Oil	3.01	0.862	0.862		
Natural Gas		0.313	0.862		

[a] Ash generation factors based on 65 percent flyash of coal ash and 70 percent collection efficiency. Assumed 80 percent of utilities use sluice (wet) removal and 20 percent dry removal (Reference A-1).

TABLE A-2. METAL EMISSION FACTORS (ng/J) — SECTOR I

	Al	Sb	As	Ba	Be	Bi	B	Cd	Co	Cr
Utility Boilers										
Anthracite		0.77×10^{-3}	77.4×10^{-3}	266.5×10^{-3}	23.2×10^{-3}	0.774×10^{-3}	7.74×10^{-3}	1.37×10^{-3}	275.1×10^{-3}	902.8×10^{-3}
Bituminous	86.0	12.0×10^{-3}	133.3×10^{-3}	193.5×10^{-3}	15.5×10^{-3}	9.02×10^{-3}	1.019	36.1×10^{-3}	32.7×10^{-3}	128.9×10^{-3}
Lignite	81.6	5.59×10^{-3}	107.5×10^{-3}	2450	20.2×10^{-3}	21.5×10^{-3}	558.9×40^{-3}	3.78×10^{-3}	34.6×10^{-3}	94.6×10^{-3}
Residual Oil	3.7	1.2×10^{-3}	1.2×10^{-3}	141.9×10^{-3}			18.5×10^{-3}	1.68×10^{-3}	73.1×10^{-3}	184.9×10^{-3}
Equipment Type	**Cu**	**Pb**	**Mn**	**Hg**	**Mo**	**Ni**	**Se**	**V**	**Zn**	**Zr**
Utility Boilers										
Anthracite	558.9×10^{-3}	98.9×10^{-3}	1419.0×10^{-3}	8.17×10^{-3}	77.4×10^{-3}	382.6×10^{-3}	4.3×10^{-3}	120.4×10^{-3}	0.25	0.146
Bituminous	356.8×10^{-3}	176.3×10^{-3}	472.9×10^{-3}	6.88×10^{-3}	73.1×10^{-3}	202.1×10^{-3}	51.6×10^{-3}	356.8×10^{-3}	2.79	0.257
Lignite	202.1×10^{-3}	111.8×10^{-3}	417.0×10^{-3}	3.39×10^{-3}	22.8×10^{-3}	98.9×10^{-3}	47.3×10^{-3}	257.9×10^{-3}	0.774	0.43
Residual Oil	150.5×10^{-3}	167.7×10^{-3}	150.5×10^{-3}	2.19×10^{-3}	150.5×10^{-3}	8.59×10^{-3}	171.9×10^{-3}	12.9	0.236	0.047

TABLE A-3. PACKAGED BOILER SULFATE AND POM EMISSION FACTORS LIQUID AND SOLID ASH STREAM GENERATION FACTORS

	Sulfates (ng/J)	POMs Low (Pg/J)	POMs High (pg/J)	Solid Removal Ash (μg/J)[a]	Liquid Removal Ash (μg/J)[a]
Watertube Wall Firing > 105 MJ/hr					
Anth	4.73	1.217	1.217	0.493	1.98
Bitum & Lignite	16.8	1.217	1.217	0.493	1.98
Resid	12.9	1.206	1.206		
Dist.	3.01	1.206	1.206		
Natural Gas	0.0	0.310	27.38		
Watertube Stoker > 105 MJ/hr					
Anth	4.73	14.33	14.33	1.845	
Bitum & Lignite	16.8	14.33	14.33	1.845	
Watertube < 105 MJ/hr					
Resid		1.206	1.206		
Dist		1.206	1.206		
Natural Gas		0.310	27.38		
Firetube Scotch					
Resid		9.73	12795		
Dist		9.73	12795		
Natural Gas		0.310	17.4		
Other					
Firetube Firebox					
Resid		9.73	12795		
Dist		9.73	12795		
Natural Gas		0.279	27.4		
Cast Iron Boilers					
Resid		14.9	14.9		
Dist		14.9	14.9		
Natural Gas		0.279	0.279		
Watertube Stoker <105 MJ/hr					
Anth		40.56	40.56		
Bitum & Lignite		40.56	40.56		
Firetube Stoker					
Anth		40.56	3354		
Bitum & Lignite		40.56	3354		

[a] Ash generation factors based on 65 percent flyash of coal ash and 70 percent collection efficiency. Assumed 80 percent of units use sluice water ash removal, 20 percent dry removal.

TABLE A-4. WARM AIR FURNACE POM EMISSION FACTORS

Equipment Type	Low POMs	High POMs
Warm Air Central Furnace		
Oil	7.8	7.8
Natural Gas	0.327	0.327
Warm Air Room Heaters		
Oil	—	—
Natural Gas	27.46	27.46
Miscellaneous Combustion		
Natural Gas	27.46	27.46

In calculating the values fi, it was assumed that if a fraction "x" of a particulate fuel (e.g., residual oil) was consumed in region "i", the fraction was equally distributed among the utility boilers firing that fuel located within the region regardless of firing type.

The form of the emission equation can be put into the convenient form

$$\text{Emissions} = (FC) \times (UEF) \times (1 - C_1) \qquad \text{(A-2)}$$

where

$$C_1 = \sum_i fi \left(1 - \frac{EFi}{UEF}\right)$$

C1, then, is the factor by which controlled NO_x emissions are lower than uncontrolled. A tabulation of control factors for utility boilers is given in Section 5.3.3.

A.3 EMISSION INVENTORY

The emission inventory of Section 5.4 was computed by calculating the emission of 29 pollutants from a variety of sources which fire a number of different fuels. Summary tables are presented in Section 5.4 and a complete listing is given here.

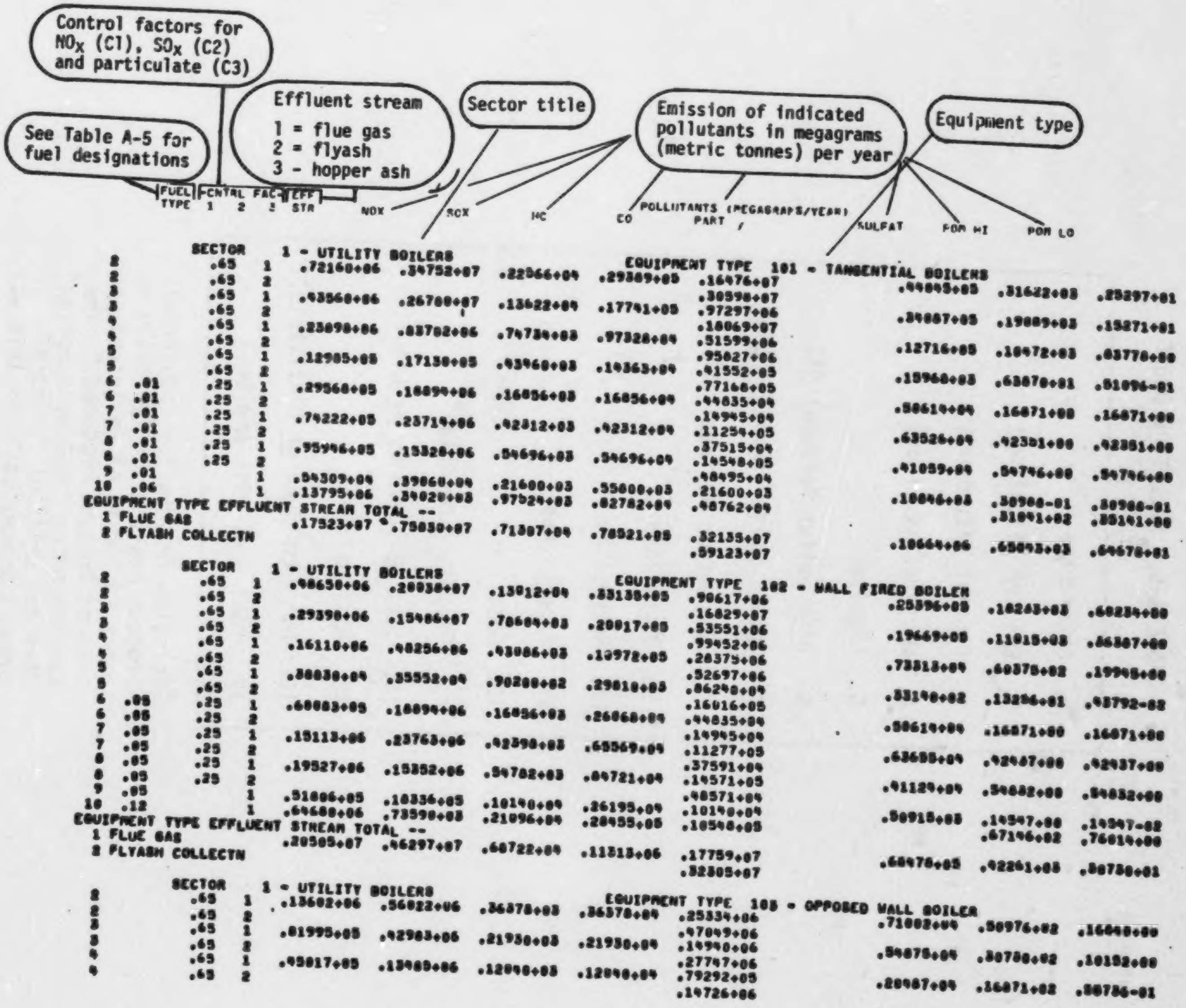
The computer program which was utilized considered each source/fuel combination in turn. Flue gas emissions were calculated as a product of (fuel consumption) x (emission factor) x $(1 - C_i)$ where C_i is a control factor. Collected flyash was calculated as (fuel consumption) x (emission factor) x C3.

After calculating emissions of each pollutant for each source/fuel combination, sector totals were calculated and listed for each fuel and effluent stream. Finally, a grand total for all sectors was calculated.

An annotated sample page of the output is shown in Figure A-1 and a list of fuel type codes is is given in Table A-5. The complete emissions listing is given in Tables A-6 through A-9. The table in which a particular pollutant species is found follows:

Table A-6	Pollutant Group i	NO_x	SO_x	H_c	CO	Part	Sulfate	POM			
Table A-7	Pollutant Group ii	Ba	Be	B	Cr	Co	Cu	Pb	Mn	Hg	Mo
Table A-8	Pollutant Group iii	Ni	V	Zn	Zr	As	Bi	Al	Sb	Cd	Se
Table A-9	Pollutant Group iv	P	Sr								

NO_x emissions for utility boilers were calculated with an assumed control level (C1) described in Section A.2. Uncontrolled NO_x emissions can be calculated by dividing the controlled emissions listed here by (1 - C1). C1 is listed for each boiler/fuel combination. Since the tables were generated from a computer listing, emissions for one equipment type sometimes overlap two pages.


Control factors for NO_x (C1), SO_x (C2) and particulate (C3)
See Table A-5 for fuel designations
Effluent stream
1 = flue gas
2 = flyash
3 - hopper ash
Sector title
Emission of indicated pollutants in megagrams (metric tonnes) per year
Equipment type

```
FUEL CNTRL FAC  EFF
TYPE  1   2   3 STR      NOX        SOX         HC         CO     POLLUTANTS (MEGAGRAMS/YEAR)
                                                                        PART  /              SULFAT      POM HI      POM LO
             SECTOR    1 - UTILITY BOILERS                        EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
 2               .65  1   .72160+06  .34752+07  .22066+04  .29309+05  .16476+07
 2               .65  2                                               .30598+07    .44045+05   .31622+03   .25297+01
 3               .65  1   .43560+06  .26700+07  .13622+04  .17741+05  .97297+06
 3               .65  2                                               .18069+07    .34087+05   .19089+03   .15271+01
 4               .65  1   .23090+06  .83702+06  .74734+03  .97328+04  .51599+06
 4               .65  2                                               .95027+06    .12716+05   .10472+03   .03770+00
 5               .65  1   .12985+05  .17130+05  .43460+03  .14363+04  .41552+05
 5               .65  2                                               .77160+05    .15960+03   .63070+01   .01096-01
 6    .01        .25  1   .29560+05  .10894+06  .16056+03  .16056+04  .44835+04
 6    .01        .25  2                                               .14945+04    .50614+04   .16071+00   .16071+00
 7    .01        .25  1   .74222+05  .23714+06  .42312+03  .42312+04  .11254+05
 7    .01        .25  2                                               .37515+04    .63526+04   .42351+00   .42351+00
 8    .01        .25  1   .95946+05  .15320+06  .54696+03  .54696+04  .14540+05
 8    .01        .25  2                                               .48495+04    .41059+04   .54746+00   .54746+00
 9    .01             1   .54309+04  .39060+04  .21600+03  .55000+03  .21600+03
10    .06             1   .13795+06  .34020+03  .97524+03  .82782+04  .48762+04    .10046+03   .30900-01   .30900-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --                                                        .31041+02   .33141+00
  1 FLUE GAS              .17523+07  .75030+07  .71307+04  .78521+05  .32135+07
  2 FLYASH COLLECTN                                                   .59123+07    .10664+06   .65043+03   .64678+01
             SECTOR    1 - UTILITY BOILERS                        EQUIPMENT TYPE  102 - WALL FIRED BOILER
 2               .65  1   .40650+06  .20038+07  .13012+04  .33138+05  .90617+06    .25396+05   .10243+03   .60234+00
 2               .65  2                                               .16029+07
 3               .65  1   .29390+06  .15406+07  .70604+03  .20017+05  .53551+06    .19669+05   .11015+03   .86307+00
 3               .65  2                                               .99452+06
 4               .65  1   .16110+06  .40256+06  .43086+03  .10972+05  .28375+06    .73313+04   .60375+02   .19945+00
 4               .65  2                                               .52697+06
 5               .65  1   .80030+04  .35552+04  .90200+02  .29010+03  .86240+04    .33140+02   .13286+01   .43792-02
 5               .65  2                                               .16016+05
 6    .05        .25  1   .60083+05  .10094+06  .16056+03  .26060+04  .44835+04    .50614+04   .16071+00   .16071+00
 6    .05        .25  2                                               .14945+04
 7    .05        .25  1   .15113+06  .23763+06  .42590+03  .65569+04  .11277+05    .63605+04   .42487+00   .42437+00
 7    .05        .25  2                                               .37591+04
 8    .05        .25  1   .19527+06  .15352+06  .54702+03  .04721+04  .14571+05    .41129+04   .54082+00   .54052+00
 8    .05        .25  2                                               .40571+04
 9    .05             1   .51006+05  .10336+05  .10140+04  .26195+04  .10140+04
10    .12             1   .64680+06  .73590+03  .21096+04  .20455+05  .10540+05    .50915+03   .14547+00   .14547-02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --                                                        .67146+02   .76014+00
  1 FLUE GAS              .20505+07  .46297+07  .60722+04  .11313+06  .17759+07
  2 FLYASH COLLECTN                                                   .32305+07    .60478+05   .42261+03   .80730+01
             SECTOR    1 - UTILITY BOILERS                        EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
 2               .65  1   .13602+06  .56022+06  .36378+03  .36378+04  .25334+06
 2               .65  2                                               .47049+06    .71002+04   .50976+02   .16040+00
 3               .65  1   .81995+05  .42983+06  .21930+03  .21930+04  .14940+06
 3               .65  2                                               .27747+06    .54075+04   .30780+02   .10152+00
 4               .65  1   .45017+05  .13489+06  .12040+03  .12040+04  .79292+05
 4               .65  2                                               .14726+06    .20987+04   .16071+02   .00786-01
```

Figure A-1. Sample emission listing.

TABLE A-5. FUEL TYPE CODES

1. Anthracite
2. Eastern Bituminous
3. Central Bituminous
4. Western Bituminous
5. Lignite
6. High Sulfur Residual Oil
7. Medium Sulfur Residual Oil
8. Low Sulfur Residual Oil
9. Distillate Oil
10. Natural Gas
11. Process Gas
12. Gasoline
13. Processed Material[a]
14. Coal (Bituminous or Lignite)
15. Residual Oil
16. Oil (Residual or Distillate)
17. Dual Fuel (Oil and Gas)

[a] Emission factors for industrial process heating are typically in units of "Grams of Pollutant per Gram of Product Produced." The corresponding "fuel consumption" then has units of "grams of product processed." In this way, all emissions can be calculated as ("fuel consumption") x (emission factor).

TABLE A-6. EMISSION INVENTORY — GROUP I POLLUTANTS

```
FUEL -CNTRL FAC- EFF                                                   POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR     NOX        SOX        HC         CO        PART                 SULFAT     POM HI     POM LO

         SECTOR    1 - UTILITY BOILERS                        EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
  2           .65  1  .72160+06  .34752+07  .22566+04  .29389+05  .16476+07            .44045+05  .31622+03  .25297+01
  2           .65  2                                              .30598+07
  3           .65  1  .43560+06  .26700+07  .13622+04  .17741+05  .97297+06            .34087+05  .19089+03  .15271+01
  3           .65  2                                              .18069+07
  4           .65  1  .23898+06  .83702+06  .74734+03  .97328+04  .51599+06            .12716+05  .10472+03  .83778+00
  4           .65  2                                              .95827+06
  5           .65  1  .12985+05  .17130+05  .43460+03  .14363+04  .41552+05            .15968+03  .63870+01  .51096-01
  5           .65  2                                              .77168+05
  6   .01     .25  1  .29568+05  .18894+06  .16856+03  .16856+04  .44835+04            .50614+04  .16871+00  .16871+00
  6   .01     .25  2                                              .14945+04
  7   .01     .25  1  .74222+05  .23714+06  .42312+03  .42312+04  .11254+05            .63526+04  .42351+00  .42351+00
  7   .01     .25  2                                              .37515+04
  8   .01     .25  1  .95946+05  .15328+06  .54696+03  .54696+04  .14548+05            .41059+04  .54746+00  .54746+00
  8   .01     .25  2                                              .48495+04
  9   .01          1  .54309+04  .39060+04  .21600+03  .55800+03  .21600+03            .10846+03  .30988-01  .30988-01
 10   .06          1  .13795+06  .34020+03  .97524+03  .82782+04  .48762+04                       .31041+02  .35141+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .17523+07  .75830+07  .71307+04  .78521+05  .32135+07            .10664+06  .65043+03  .64678+01
  2 FLYASH COLLECTN                                               .59123+07

         SECTOR    1 - UTILITY BOILERS                        EQUIPMENT TYPE  102 - WALL FIRED BOILER
  2           .65  1  .48650+06  .20038+07  .13012+04  .33135+05  .90617+06            .25396+05  .18233+03  .60234+00
  2           .65  2                                              .16829+07
  3           .65  1  .29390+06  .15406+07  .78604+03  .20017+05  .53551+06            .19669+05  .11015+03  .36387+00
  3           .65  2                                              .99452+06
  4           .65  1  .16110+06  .48256+06  .43086+03  .10972+05  .28375+06            .73313+04  .60375+02  .19945+00
  4           .65  2                                              .52697+06
  5           .65  1  .38830+04  .35552+04  .90200+02  .29810+03  .86240+04            .33140+02  .13256+01  .43792-02
  5           .65  2                                              .16016+05
  6   .05     .25  1  .60083+05  .18894+06  .16856+03  .26068+04  .44835+04            .50614+04  .16871+00  .16871+00
  6   .05     .25  2                                              .14945+04
  7   .05     .25  1  .15113+06  .23763+06  .42398+03  .65569+04  .11277+05            .63655+04  .42437+00  .42437+00
  7   .05     .25  2                                              .37591+04
  8   .05     .25  1  .19527+06  .15352+06  .54782+03  .84721+04  .14571+05            .41124+04  .54832+00  .54832+00
  8   .05     .25  2                                              .48571+04
  9   .05          1  .51806+05  .18336+05  .10140+04  .26195+04  .10140+04            .50915+03  .14547+00  .14547-02
 10   .12          1  .64680+06  .73590+03  .21096+04  .28455+05  .10548+05                       .67146+02  .76014+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .20505+07  .46297+07  .68722+04  .11313+06  .17759+07            .68478+05  .42261+03  .30730+01
  2 FLYASH COLLECTN                                               .32305+07

         SECTOR    1 - UTILITY BOILERS                        EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
  2           .65  1  .13602+06  .56022+U6  .36378+03  .36378+04  .25334+06            .71002+U4  .50976+U2  .16840+0U
  2           .65  2                                              .47049+06
  3           .65  1  .81995+05  .42983+06  .21930+03  .21930+04  .14940+06            .54875+04  .30730+U2  .10152+00
  3           .65  2                                              .27747+06
  4           .65  1  .45017+05  .13485+06  .12040+03  .12040+04  .79292+05            .20487+04  .16871+02  .55736-01
  4           .65  2                                              .14726+06
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                            POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1    2   3  STR        NOX         SOX         HC          CO          PART                        SULFAT      POM HI      POM LO

SECTOR     1 TOTAL
                         .55644+07   .16767+08   .29445+05   .26960+06   .16877+08                   .23267+06   .12137+04   .13778+02

  BY FUEL --
  1 ANTHRACITE           .29321+05   .38259+05   .32809+03   .10028+05   .39562+05                   .51604+03   .11963-01   .11963-01
  2 EASTERN BITUMIN.     .14606+07   .64396+07   .55556+04   .72948+05   .83080+07                   .81039+05   .54983+03   .36029+01
  3 CENTRAL BITUMIN.     .15513+07   .73059+07   .11316+05   .67263+05   .53826+07                   .89414+05   .33415+03   .43790+01
  4 WESTERN BITUMIN.     .44509+06   .14544+07   .12986+04   .21909+05   .25115+07                   .22096+05   .18197+03   .10930+01
  5 LIGNITE              .77940+05   .74659+05   .18898+04   .64995+04   .51806+06                   .69594+03   .10496+02   .31660+00
  6 HIGH S RES. OIL      .11639+06   .46585+06   .47730+03   .54659+04   .14731+05                   .12473+05   .41576+00   .41576+00
  7 MED  S RES. OIL      .29224+06   .58446+06   .11868+04   .13710+05   .36966+05                   .15649+05   .10433+01   .10433+01
  8 LOW  S RES. OIL      .37809+06   .37807+06   .15394+04   .17740+05   .47824+05                   .10123+05   .13497+01   .13497+01
  9 DISTILLATE OIL       .61835+05   .23870+05   .13200+04   .34025+04   .13200+04                   .66280+03   .18957+00   .45355-01
 10 NATURAL GAS          .11516+07   .14553+04   .45339+04   .50639+05   .16227+05                               .13429+03   .15203+01

  BY EFFLUENT STREAMS --
  1 FLUE GAS             .55644+07   .16767+08   .29445+05   .26960+06   .59600+07                   .23267+06   .12137+04   .13778+02
  2 FLYASH COLLECTN                                                      .10917+08

      - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-6. Continued

```
                                                     POLLUTANTS (MEGAGRAMS/YEAR)
FUEL  -CNTRL FAC-  EFF
TYPE   1    2    3   STR    NOX        SOX         HC         CO        PART       SULFAT     POM HI     POM LO

  5             .65   1   .74130+04  .67872+04  .17220+03  .56910+03  .16464+05  .63268+02  .25307+01  .83604-02
  5             .65   2                                               .30576+05
  6   .05       .25   1   .24217+05  .76156+05  .67940+02  .98750+03  .18071+04  .20401+04  .68002-01  .68002-01
  6   .05       .25   2                                               .60237+03
  7   .05       .25   1   .61002+05  .95918+05  .17114+03  .24875+04  .45521+04  .25694+04  .17150+00  .17130+00
  7   .05       .25   2                                               .15174+04
  8   .05       .25   1   .79088+05  .62178+05  .22188+03  .32250+04  .59017+04  .16656+04  .22208+00  .22208+00
  8   .05       .25   2                                               .19672+04
  9   .05             1   .45982+04  .16275+04  .90000+02  .22500+03  .90000+02  .45191+02  .12912-01  .12912-01
 10   .07             1   .35215+06  .37740+03  .10819+04  .13461+05  .54094+03             .34455+02  .38983+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   1 FLUE GAS             .79150+06  .13679+07  .25085+04  .27989+05  .51140+06  .21020+05  .13602+03  .11981+01
   2 FLYASH COLLECTN                                                  .92988+06

                                                  EQUIPMENT TYPE  104 - CYCLONE BOILER
            SECTOR    1 - UTILITY BOILERS
  2   .02       .75   1   .86856+05  .23602+06  .10191+04  .28598+04  .12973+05  .26521+04  .29037+00  .29037+00
  2   .02       .75   2                                               .38920+05
  3   .02       .75   1   .71024+06  .24564+07  .83334+04  .23385+05  .10378+06  .27803+05  .23744+01  .23744+01
  3   .02       .75   2                                               .31134+06
  5             .75   1   .51238+05  .44278+05  .11193+04  .37127+04  .76501+05  .41275+03  .25178+00  .25178+00
  5             .75   2                                               .22950+06
  6   .04       .25   1   .25255+04  .11808+05  .72240+02  .18600+03  .27450+03  .30988+03  .10329-01  .10329-01
  6   .04       .25   2                                               .91500+02
  7   .04       .25   1   .58929+04  .13776+05  .16856+03  .43400+03  .64050+03  .36153+03  .24102-01  .24102-01
  7   .04       .25   2                                               .21350+03
  8   .04       .25   1   .77870+04  .91020+04  .22274+03  .57350+03  .84637+03  .23887+03  .31849-01  .31849-01
  8   .04       .25   2                                               .28212+03
 10                   1   .14701+05  .18300+01  .36722+03  .44530+03  .26250+03             .16697+01  .18903-01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   1 FLUE GAS             .87924+06  .27713+07  .11303+05  .31596+05  .19528+06  .31778+05  .46526+01  .30017+01
   2 FLYASH COLLECTN                                                  .58035+06

                                                  EQUIPMENT TYPE  105 - VERTICAL + STOKER BOILER
            SECTOR    1 - UTILITY BOILERS
  1             .50   1   .29321+05  .38259+05  .32809+03  .10028+05  .19781+05  .51604+03  .11963-01  .11963-01
  1             .50   2                                               .19781+05
  2             .50   1   .29590+05  .16432+06  .61490+03  .39270+04  .11790+06  .18464+04  .12072-01  .12072-01
  2             .50   2                                               .11790+06
  3             .50   1   .29590+05  .20913+06  .61490+03  .39270+04  .11533+06  .23672+04  .12072-01  .12072-01
  3             .50   2                                               .11533+06
  5             .50   1   .24210+04  .29088+04  .73530+02  .48330+03  .10829+05  .27115+02  .98775-03  .98775-03
  5             .50   2                                               .10829+05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
   1 FLUE GAS             .90922+05  .41462+06  .16314+04  .18365+05  .26384+06  .47567+04  .37095-01  .37095-01
   2 FLYASH COLLECTN                                                  .26384+06
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                          POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR     NOX        SOX         HC         CO        PART                  SULFAT     POM HI     POM LO


          SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  201 - WALL FIRED W-TUBE  >29.5
   9              1  .27370+05  .92225+04  .25500+03  .33150+03  .65790+03             .25608+03  .10243+00  .10353+00
  10              1  .27933+06  .27840+03  .36192+04  .83520+04  .15962+04                        .25402+02  .28757+00
  11              1  .39130+05  .39000+02  .50700+03  .11700+04  .22360+03                        .35585+01  .40285-01
  14        .50   1  .16422+06  .62720+06  .11220+04  .20400+02  .43636+06             .85605+04  .61460+00  .62118+00
  14        .50   2                                              .43636+06
  15        .05   1  .20511+06  .25990+06  .19110+04  .24843+04  .23661+05             .82248+04  .76765+00  .77587+00
  15        .05   2                                              .12453+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .71516+06  .89663+06  .74142+04  .12358+05  .46250+06             .17041+05  .30445+02  .18284+01
  2 FLYASH COLLECTN                                              .43760+06

          SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  202 - STOKER W-TUBE      >29.5
  14        .50   1  .12535+06  .77566+06  .20038+04  .11650+05  .49946+06             .78219+04  .54754+00  .56759+00
  14        .50   2                                              .49946+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .12535+06  .77566+06  .20038+04  .11650+05  .49946+06             .78219+04  .54754+00  .56759+00
  2 FLYASH COLLECTN                                              .49946+06

          SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29.5
   9              1  .69525+04  .11175+05  .44290+02  .16480+03  .84460+03             .31031+03  .12413+00  .12058+00
  10              1  .16714+06  .57460+04  .28730+04  .14534+05  .57460+04             .43642+05  .46260+02  .52370+00
  11              1  .12857+05  .44200+03  .22100+03  .11180+04  .44200+03                        .35505+01  .40285-01
  15              1  .10948+06  .28679+06  .51170+03  .20230+04  .23264+05             .76825+04  .71703+00  .69655+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .29643+06  .30415+06  .36500+04  .17840+05  .30297+05             .51635+05  .50660+02  .13811+01

          SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29.5
   9              1  .30105+05  .48391+05  .19178+03  .71360+03  .32558+04             .13437+04  .57011+04  .43382+01
  10              1  .96131+05  .29160+02  .16524+04  .83592+04  .25272+04                        .26606+05  .27067+00
  11              1  .18791+04  .57000+00  .32500+02  .16340+03  .49400+02                        .52009+03  .58678-02
  15              1  .17388+06  .45549+06  .81270+03  .32130+04  .36949+05             .12202+05  .12080+05  .91919+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .30199+06  .50391+06  .26892+04  .12449+05  .42782+05             .13545+05  .44907+05  .13807+02

          SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29.5
   9              1  .27202+05  .43725+05  .17329+03  .64480+03  .29419+04             .12141+04  .51514+04  .39199+01
  10              1  .88911+05  .26970+03  .15283+04  .77314+04  .23374+04                        .25034+00  .25034+00
  11              1  .18791+04  .57000+01  .32500+02  .16340+03  .49400+02                        .52908-02  .52908-02
  15              1  .11206+06  .29354+06  .52374+03  .20706+04  .23812+05             .78633+04  .77846+04  .59237+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS         .23005+06  .33754+06  .22576+04  .10610+05  .29141+05             .90774+04  .12956+05  .10099+02

          SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  206 - STOKER FIRED W-TUBE <100
   1        .15   1  .37590+04  .73710+04  .63000+02  .19320+04  .65849+04             .99421+02  .24674-01  .85140+00
   1        .15   2                                              .11620+04
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                             POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NOX        SOX         HC         CO        PART                    SULFAT     POM HI     POM LO

 14          .15  1   .27441+06  .22664+07  .27594+05  .32193+05  .27812+07                .25732+05  .18012+01  .62152+02
 14          .15  2                                               .49081+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .27817+06  .22738+07  .27657+05  .34125+05  .27878+07                .25831+05  .18259+01  .63004+02
  2 FLYASH COLLECTN                                               .49197+06

         SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  208 - CAST IRON BOILERS
  9               1   .12217+05  .19638+05  .77830+02  .28960+03  .66970+03                .54531+03  .26954+01  .26954+01
 10               1   .13622+05  .79200+02  .68640+03  .22704+04  .44880+03                           .73514-01  .73514-01
 15               1   .35880+05  .93990+05  .16770+03  .66300+03  .76245+04                .25178+04  .29039+01  .29039+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .61720+05  .11371+06  .93193+03  .32230+04  .87430+04                .30631+04  .56727+01  .56727+01

         SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  209 - STOKER F-T BOILER  <29.3
  1          .15  1   .75180+04  .14742+05  .12600+03  .38640+04  .13170+05                .19884+03  .14082+03  .17046+01
  1          .15  2                                               .23241+04
 14          .15  1   .99524+05  .82199+06  .10008+05  .11676+05  .10087+07                .93326+04  .18641+04  .22566+02
 14          .15  2                                               .17801+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .10704+06  .83673+06  .10134+05  .15540+05  .10219+07                .95315+04  .20049+04  .24270+02
  2 FLYASH COLLECTN                                               .18033+06

         SECTOR    2 - PACKAGED BOILERS                      EQUIPMENT TYPE  210 - HRT BOILERS   <29.3 MJ/S
  9               1   .17752+05  .28667+05  .10520+03  .44710+03  .10257+04                .79235+03  .33618+04  .25582+01
 10               1   .52911+05  .16050+03  .90950+03  .46010+04  .13910+04                           .14645+02  .16579+00
 15               1   .68265+05  .17834+06  .33300+03  .12580+04  .30710+05                .47774+04  .47296+04  .35989+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .13893+06  .20717+06  .13477+04  .63061+04 . .33127+05                .55697+04  .81061+04  .63229+01

         SECTOR    2 - PACKAGED BOILENS                      EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
  1               1   .25102+04  .49140+04  .42980+04  .19320+04  .42980+04                .66280+02  .11147+02  .11147+02
  9               1   .48400+05  .95480+05  .41624+04  .26840+05  .67760+04                .26512+04  .13105+02  .13105+02
 10               1   .25353+05  .19162+03  .25058+04  .63382+04  .31691+04                           .20523+00  .20523+00
 14               1   .19723+04  .16432+05  .39402+04  .17737+05  .39402+04                .18464+03  .87585+01  .87585+01
 15               1   .11178+05  .33189+05  .20769+03  .10681+04  .57270+04                .89091+03  .10275+03  .10275+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .89413+05  .15021+06  .15114+05  .53916+05  .23910+05                .37930+04  .13597+03  .34243+02
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                           POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR        NOX        SOX        HC         CO        PART                   SULFAT     POM HI     POM LO

SECTOR    2 TOTAL
                         .23443+07  .63995+07  .73200+05  .17802+06  .65490+07              .14691+06  .68180+05  .16120+03

  BY FUEL --
 1 ANTHRACITE            .13787+05  .27027+05  .44870+04  .77280+04  .27539+05              .36454+03  .15199+03  .13703+02
 9 UISTILLATE OIL        .17000+06  .25630+06  .50098+04  .29431+05  .16172+05              .71131+04  .14230+05  .26840+02
10 NATURAL GAS           .72340+06  .67546+04  .13775+05  .52186+05  .17216+05              .43642+05  .26693+05  .17768+01
11 PROCESS GAS           .55745+05  .48727+03  .79260+03  .26148+04  .76440+03                         .52721+03  .91748-01
14 BIT/LIG COAL          .66548+06  .45077+07  .44668+05  .73277+05  .63343+07              .51632+05  .18759+04  .94665+02
15 RESIDUAL OIL          .71585+06  .16012+07  .44675+04  .12780+05  .15299+06              .44158+05  .24701+05  .24118+02

  BY EFFLUENT STREAMS --
 1 FLUE GAS              .23443+07  .63995+07  .73200+05  .17802+06  .49397+07              .14691+06  .68180+05  .16120+03
 2 FLYASH COLLECTN                                                   .16094+07

   - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                        POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NOX        SOX        HC         CO         PART                   SULFAT     POM HI     POM LO

          SECTOR    3 - WARM AIR FURNACES                 EQUIPMENT TYPE  301 - WARM AIR CENTRAL FURNACE
 10               1   .10633+06  .11066+U4  .10509+05  .37092+05  .13291+05                         .10111+01  .10111+01
 16               1   .85705+05  .15244+U6  .66U35+04  .43555+05  .10818+05              .42329+04  .10945+02  .10945+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .19204+06  .15355+06  .17113+05  .80647+05  .24110+05              .42329+04  .11956+02  .11956+02

          SECTOR    3 - WARM AIR FURNACES                 EQUIPMENT TYPE  302 - WARM AIR SPACE HEATER
 10               1   .49914+05  .37436+03  .49334+04  .17412+05  .62393+04                         .39718+02  .39843+02
 16               1   .44347+05  .78879+05  .34169+04  .22537+05  .55979+04              .21903+04  .56634+01  .56634+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .94261+05  .79254+05  .83503+04  .39949+05  .11837+05              .21903+04  .45382+02  .45506+02

          SECTOR    3 - WARM AIR FURNACES                 EQUIPMENT TYPE  303 - MISCELLANEOUS COMBUSTION
 10               1   .34400+05  .25800+03  .34000+04  .12000+05  .43000+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .34400+05  .25800+03  .34000+04  .12000+05  .43000+04
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                                POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR       NOX         SOX         HC          CO         PART                      SULFAT      POM HI      POM LO

SECTOR    3 TOTAL
                        .32070+06   .23306+06   .28863+05   .13260+06   .40247+05                 .64232+04   .57338+02   .57463+02

  BY FUEL --
10 NATURAL GAS          .19064+06   .17389+04   .18843+05   .66504+05   .23831+05                             .40729+02   .40854+02
16 OIL                  .13005+06   .23132+06   .10020+05   .66092+05   .16416+05                 .64232+04   .16608+02   .16608+02

  BY EFFLUENT STREAMS --
 1 FLUE GAS             .32070+06   .23306+06   .28863+05   .13260+06   .40247+05                 .64232+04   .57338+02   .57463+02

       - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                           POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NOX        SOX        HC         CO         PART                 SULFAT     POM HI     POM LO


          SECTOR    4 - GAS TURBINES                     EQUIPMENT TYPE  401 - SIMPLE CYCLE    >15 MJ/S
  9               1   .96360+05  .28248+04  .22704+04  .12408+05  .42240+04
 10               1   .41340+05  .46640+03  .18232+04  .10388+05  .12720+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .13770+06  .32912+04  .40936+04  .22796+05  .54960+04

          SECTOR    4 - GAS TURBINES                     EQUIPMENT TYPE  402 -
  9               1   .21133+06  .61953+04  .57321+04  .27387+05  .89745+04
 10               1   .90792+05  .10296+04  .38376+04  .23119+05  .28080+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .30213+06  .72249+04  .95697+04  .50506+05  .11782+05

          SECTOR    4 - GAS TURBINES                     EQUIPMENT TYPE  403 -
  9               1   .36500+03  .10700+02  .99000+01  .47300+02  .15500+02
 10               1   .19400+03  .22000+01  .82000+01  .49400+02  .60000+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .55900+03  .12900+02  .18100+02  .96700+02  .21500+02
```

TABLE A-6. Continued

```
                                                          POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF                                                                    SULFAT    POM HI    POM LO
TYPE  1   2   3  STR      NOX        SOX        HC         CO        PART

SECTOR    4 TOTAL
                       .44039+06  .10529+05  .13681+05  .73399+05  .17300+05

  BY FUEL --
  9 DISTILLATE OIL     .30806+06  .90308+04  .80124+04  .39842+05  .13214+05
 10 NATURAL GAS        .13233+06  .14982+04  .56690+04  .33557+05  .40860+04

  BY EFFLUENT STREAMS --
  1 FLUE GAS           .44039+06  .10529+05  .13681+05  .73399+05  .17300+05
     - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                                  POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NOX        SOX        HC          CO          PART
                                                                                        SULFAT     POM HI     POM LO
          SECTOR    5 - RECIPROCATING I/C ENGINE                 EQUIPMENT TYPE  501 - C. I.      >75 KJ/S/CYL
  9                1   .94014+05  .51786+04  .62100+04  .16902+05  .55620+04
 17                1   .71610+05                        .29099+05  .95998+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .16562+06  .51786+04  .35509+05  .26502+05  .55620+04

          SECTOR    5 - RECIPROCATING I/C ENGINE                 EQUIPMENT TYPE  502 - S. I.      >75 KJ/S/CYL
 10                1   .12618+07  .17886+03  .45121+06  .14390+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .12618+07  .17886+03  .45121+06  .14390+06

          SECTOR    5 - RECIPROCATING I/C ENGINE                 EQUIPMENT TYPE  503 - C. I. 75KJ/S-75 KJ/S/CYL
  9                1   .22459+06  .12371+05  .14835+05  .40377+05  .13287+05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .22459+06  .12371+05  .14835+05  .40377+05  .13287+05

          SECTOR    5 - RECIPROCATING I/C ENGINE                 EQUIPMENT TYPE  504 - S. I. 75KJ/S-75 KJ/S/CYL
 10                1   .66736+05  .94600+01  .23865+05  .76110+04
 12                1   .10038+06  .13692+04  .34020+05  .10148+07  .16632+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .16712+06  .13787+04  .57885+05  .10224+07  .16632+04

          SECTOR    5 - RECIPROCATING I/C ENGINE                 EQUIPMENT TYPE  506 - S. I.             <75 KJ/S
 12                1   .37926+05  .79870+03  .19845+05  .59197+06  .97020+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS           .37926+05  .79870+03  .19845+05  .59197+06  .97020+03
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                     POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NOX        SOX        HC         CO         PART                  SULFAT     POM HI     POM LO

SECTOR    5 TOTAL
                        .18570+07  .19906+05  .57909+06  .18252+07  .21482+05

   BY FUEL --
  9 UISTILLATE OIL      .31860+06  .17550+05  .21045+05  .57279+05  .18849+05
 10 NATURAL GAS         .13285+07  .18832+03  .47508+06  .15151+06
 12 GASOLINE            .13831+06  .21679+04  .53865+05  .16068+07  .26334+04
 17 DUAL (OIL + GAS)    .71610+05             .29099+05  .95998+04

   BY EFFLUENT STREAMS --
  1 FLUE GAS            .18570+07  .19906+05  .57909+06  .18252+07  .21482+05

      - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-6. Continued

```
FUEL -CNTRL FAC- EFF                                          POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NOX        SOX         HC         CO        PART                 SULFAT     POM HI     POM LO

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  601 - CEMENT KILNS
 13          .88  1   .10005+05  .39173+05                          .11267+06
 13          .88  2                                                 .82624+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .10005+05  .39173+05                          .11267+06
  2 FLYASH COLLECTN                                                 .82624+06

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  602 - GLASS MELTING FURNACES
 13               1   .56746+05  .32690+05                          .15420+05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .56746+05  .32690+05                          .15420+05

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  603 - GLASS ANNEALING LEHRS
 13               1   .10640+05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .10640+05

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  604 - COKE OVEN UNDERFIRE
 13               1   .39907+04  .16191+06                          .21493+07
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .39907+04  .16191+06                          .21493+07

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  605 - STEEL SINTERING MACHINES
 13               1   .25225+04  .34442+04              .10672+06  .48510+05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .25225+04  .34442+04              .10672+06  .48510+05

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  606 - OPEN HEARTH FURNCE (OIL)
 13               1   .20007+05  .22589+05                          .19362+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .20007+05  .22589+05                          .19362+06

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  607 - BRICK + CERAMIC KILNS
 13               1   .15790+05  .17053+05  .12632+04  .31580+04  .20527+07
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .15790+05  .17053+05  .12632+04  .31580+04  .20527+07

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  608 - CAT CRACKING (FCCU)
 13               1   .45880+05  .32345+06  .14452+06  .89695+07  .15829+06
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .45880+05  .32345+06  .14452+06  .89695+07  .15829+06

         SECTOR    6 - IND. PROCESS COMBUSTION               EQUIPMENT TYPE  609 - REFINERY FLARES
```

TABLE A-6. Continued

```
                                                         POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR      NOX        SOX        HC        CO       PART                 SULFAT     POM HI     POM LO

 13             1   .77730+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .77730+04

         SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  611 - IRON + STEEL FLARES
 13             1   .31800+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .31800+03

         SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  612 - OPEN HEARTH FURNCE (GAS)
 13             1   .78442+05  .13764+04  .14435+05                .96234+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .78442+05  .13764+04  .14435+05                .96234+04

         SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  613 -
 13             1   .39706+05  .16083+05  .33525+04                .20110+05
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
. 1 FLUE GAS        .39706+05  .16083+05  .33525+04                .20110+05

         SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  614 -
 13             1   .14166+05  .15769+03  .16538+04                .11025+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .14166+05  .15769+03  .16538+04                .11025+04

         SECTOR    6 - IND. PROCESS COMBUSTION           EQUIPMENT TYPE  615 -
 13             1   .14871+05  .50536+04  .10534+04                .63190+04
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .14871+05  .50536+04  .10534+04                .63190+04
```

TABLE A-6. Continued

```
                                                                       POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF                                                          PART                    SULFAT      POM HI      POM LO
TYPE  1   2   3  STR        NOX          SOX          HC           CO

SECTOR     6 TOTAL                                                            .55939+07
                         .32086+06    .62298+06    .16628+06    .90794+07

   BY FUEL --
 13 PROCESSED MAT'L      .32086+06    .62298+06    .16628+06    .90794+07    .55939+07

   BY EFFLUENT STREAMS --                                                    .47676+07
  1 FLUE GAS             .32086+06    .62298+06    .16628+06    .90794+07    .82624+06
  2 FLYASH COLLECTN
        - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-6. Concluded

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	NOX	SOX	HC	CO	PART	SULFAT	POM HI	POM LO
	POLLUTANTS (MEGAGRAMS/YEAR)							
GRAND TOTAL								
	.10848+08	.24053+08	.89056+06	.11558+08	.29099+08	.38600+06	.69451+05	.23244+03
BY FUEL --								
1 ANTHRACITE	.43108+05	.65286+05	.48151+04	.17756+05	.67100+05	.88058+03	.15200+03	.13715+02
2 EASTERN BITUMIN.	.14606+07	.64396+07	.55556+04	.72948+05	.83080+07	.81039+05	.54983+03	.36029+01
3 CENTRAL BITUMIN.	.15513+07	.73059+07	.11316+05	.67263+05	.53826+07	.89414+05	.33415+03	.43790+01
4 WESTERN BITUMIN.	.44509+06	.14544+07	.12986+04	.21909+05	.25115+07	.22096+05	.18197+03	.10930+01
5 LIGNITE	.77940+05	.74659+05	.18898+04	.64995+04	.51806+06	.69594+03	.10496+02	.31660+00
6 HIGH S RES. OIL	.11639+06	.46585+06	.47730+03	.54659+04	.14731+05	.12473+05	.41576+00	.41576+00
7 MED S RES. OIL	.29224+06	.58446+06	.11868+04	.13710+05	.36966+05	.15649+05	.10433+01	.10433+01
8 LOW S RES. OIL	.37809+06	.37807+06	.15394+04	.17740+05	.47824+05	.10123+05	.13497+01	.13497+01
9 DISTILLATE OIL	.85850+06	.30675+06	.35387+05	.12995+06	.49555+05	.77759+04	.14231+05	.26886+02
10 NATURAL GAS	.35265+07	.11635+05	.51790+06	.35440+06	.61360+05	.43642+05	.26868+05	.44151+02
11 PROCESS GAS	.55745+05	.48727+03	.79260+03	.26148+04	.76440+03		.52721+03	.91748-01
12 GASOLINE	.13831+06	.21679+04	.53865+05	.16068+07	.26334+04			
13 PROCESSED MAT'L	.32086+06	.62298+06	.16628+06	.90794+07	.55939+07			
14 BIT/LIG COAL	.66548+06	.45077+07	.44668+05	.73277+05	.63343+07	.51632+05	.18759+04	.94665+02
15 RESIDUAL OIL	.71585+06	.16012+07	.44675+04	.12780+05	.15299+06	.44158+05	.24701+05	.24118+02
16 OIL	.13005+06	.23132+06	.10020+05	.66092+05	.16416+05	.64232+04	.16608+02	.16608+02
17 DUAL (OIL + GAS)	.71610+05		.29099+05	.95998+04				

TABLE A-7. EMISSION INVENTORY — GROUP II POLLUTANTS

```
                                                      POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR       BA          BE          B          CR          CO          CU          PB          MN          HG          MO

              SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
 2            .65  1  .50821+03  .40431+02  .26766+04  .33316+03  .86056+02  .93736+03  .46303+03  .12536+04  .17844+02  .10747+03
 2            .65  3  .16998+04  .80740+02  .53931+04  .53305+03  .51611+03  .13100+04  .19877+03  .25072+04  .98018+00  .29920+03
 3            .65  1  .30678+03  .24406+02  .16157+04  .20111+03  .51949+02  .56504+03  .27951+03  .75673+03  .10772+02  .11317+03
 3            .65  3  .10226+04  .48744+02  .32315+04  .32178+03  .31156+03  .79082+03  .11999+03  .15145+04  .59652+00  .10866+03
 4            .65  1  .16830+03  .13390+02  .88641+03  .11033+03  .28500+02  .51043+03  .15334+03  .41515+03  .59094+01  .62086+02
 4            .65  3  .56102+03  .26742+02  .17728+04  .17653+03  .17092+03  .43385+03  .65826+02  .83030+03  .32726+00  .99113+02
 5            .65  1  .12934+03  .10721+01  .29198+02  .49956+01  .18340+01  .10721+02  .59764+01  .22126+02  .17975+00  .12090+01
 5            .65  3  .43112+03  .21442+01  .58396+02  .79838+01  .10995+02  .15009+02  .12820+01  .44253+02  .99911-02  .19344+01
 6  .01       .25  1  .27838+02             .36273+01  .36273+02  .14341+02  .29525+02  .32899+02  .29525+02  .43022+00  .29525+02
 6  .01       .25  3  .92793+02             .72547+02  .57363+02  .84357+02  .41335+02  .14341+02  .59050+02  .24463-01  .47240+01
 7  .01       .25  1  .69878+02             .91054+01  .91054+02  .35998+02  .74114+02  .82584+02  .74114+02  .10799+01  .74114+02
 7  .01       .25  3  .23293+03             .10211+03  .14399+03  .21175+03  .10376+03  .35998+02  .14823+03  .61408-01  .11850+02
 8  .01       .25  1  .90331+02             .11770+02  .11770+03  .46534+02  .95805+02  .10675+03  .95805+02  .13960+01  .95805+02
 8  .01       .25  3  .30110+03             .23541+03  .10614+03  .27373+03  .13413+03  .46534+02  .19161+03  .79381-01  .15329+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .13087+04  .79299+02  .52324+04  .89463+03  .26521+03  .20238+04  .11241+04  .26478+04  .37611+02  .56830+04
  3 BOTTM HOPPER ASH  .43356+04  .15838+03  .10986+05  .14268+04  .15794+04  .28289+04  .40273+03  .52941+04  .20872+01  .61290+03

              SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  102 - WALL FIRED BOILER
 2            .65  1  .29303+03  .23312+02  .15433+04  .19210+03  .49620+02  .54048+03  .26699+03  .72281+03  .10289+02  .10810+03
 2            .65  3  .97677+03  .46560+02  .30866+04  .30736+03  .29759+03  .75537+03  .11461+03  .14456+04  .56979+00  .17256+03
 3            .65  1  .17702+03  .14083+02  .93231+03  .11605+03  .29975+02  .32650+03  .16129+03  .43665+03  .62154+01  .65301+02
 3            .65  3  .59087+03  .28127+02  .18646+04  .18567+03  .17977+03  .45632+03  .69235+02  .87330+03  .34421+00  .10425+03
 4            .65  1  .97032+02  .77194+01  .51103+03  .63610+02  .16431+02  .17897+03  .88407+02  .23935+03  .34069+01  .35794+02
 4            .65  3  .32344+03  .15417+02  .10221+04  .10178+03  .98541+02  .25013+03  .37930+02  .47869+03  .18867+00  .57141+02
 5            .65  1  .26084+02  .22251+00  .60599+01  .10368+01  .38064+00  .22251+01  .12404+01  .45923+01  .87306-01  .25092+00
 5            .65  3  .89470+02  .44503+00  .12120+02  .16570+01  .22819+01  .31152+01  .26607+00  .91846+01  .20736-02  .40147+00
 6  .05       .25  1  .27838+02             .36273+01  .36273+02  .14341+02  .29525+02  .32899+02  .29525+02  .43022+00  .29525+02
 6  .05       .25  3  .92793+02             .72547+02  .57363+02  .84357+02  .41335+02  .14341+02  .59050+02  .24463-01  .47240+01
 7  .05       .25  1  .78026+02             .91239+01  .91239+02  .36871+02  .74264+02  .82751+02  .74264+02  .10021+01  .74264+02
 7  .05       .25  3  .23340+03             .18248+03  .14428+03  .21218+03  .10397+03  .36071+02  .14853+03  .61533-01  .11882+02
 8  .05       .25  1  .90473+02             .11789+02  .11789+03  .46607+02  .95956+02  .10692+03  .95956+02  .13982+01  .95956+02
 8  .05       .25  3  .30158+03             .23578+03  .10643+03  .27416+03  .13434+03  .46607+02  .19191+03  .79506-01  .15353+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .78226+03  .45337+02  .30172+04  .61019+03  .19343+03  .12479+04  .74849+03  .16081+04  .22859+02  .40919+03
  3 BOTTM HOPPER ASH  .26075+04  .90548+02  .64762+04  .98454+03  .11489+04  .17446+04  .31900+03  .32063+04  .12782+01  .36631+03

              SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
 2            .65  1  .81925+02  .65176+01  .43147+03  .55706+02  .13873+02  .15111+03  .74643+02  .20208+03  .28765+01  .30221+02
 2            .65  3  .27308+03  .13017+02  .86294+03  .85930+02  .83200+02  .21118+03  .32842+02  .40416+03  .15930+00  .40245+02
 3            .65  1  .49387+02  .39290+01  .26011+03  .32376+02  .83629+01  .91092+02  .44997+02  .12182+03  .17340+01  .18218+02
 3            .65  3  .16462+03  .78471+01  .52021+03  .51802+02  .50156+02  .12731+03  .19316+02  .24364+03  .96031-01  .29084+02
 4            .65  1  .27115+02  .21571+01  .14280+03  .17775+02  .45914+01  .50012+02  .24705+02  .66803+02  .95203+00  .10002+02
 4            .65  3  .90382+02  .43082+01  .28561+03  .20440+02  .27536+02  .69096+02  .10605+02  .13377+03  .52723-01  .15960+02
 5            .65  1  .51247+02  .42480+00  .11569+02  .19794+01  .72667+00  .42480+01  .23600+01  .87671+01  .71221-01  .47903+00
 5            .65  3  .17082+03  .84959+00  .23138+02  .31634+01  .43564+01  .59472+01  .50795+00  .17554+02  .39587-02  .76644+00
 6  .05       .25  1  .11220+02             .14620+01  .14620+02  .57802+01  .11900+02  .13260+02  .11900+02  .17340+00  .11900+02
 6  .05       .25  3  .37401+02             .29241+02  .23121+02  .34801+02  .16660+02  .57802+01  .23801+02  .90603-02  .19041+01
```

TABLE A-7. Continued

POLLUTANTS (MEGAGRAMS/YEAR)

FUEL TYPE	-CNTRL FAC- 1	2	3	EFF STR	BA	BE	B	CR	CO	CU	PB	MN	HG	MO
7	.05		.25	1	.28264+02		.36029+01	.36029+02	.14560+02	.29977+02	.33403+02	.29977+02	.43600+00	.29977+02
7	.05		.25	3	.94213+02		.73657+02	.50241+02	.85644+02	.41968+02	.14560+02	.59954+02	.24038-01	.47963+01
8	.05		.25	1	.36644+02		.47740+01	.47740+02	.10077+02	.38064+02	.43306+02	.38064+02	.56631+00	.38064+02
8	.05		.25	3	.12215+03		.95495+02	.75508+02	.11109+03	.54410+02	.10077+02	.77729+02	.32202-01	.62103+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.28588+03	.13029+02	.85587+03	.28503+03	.66771+02	.57720+03	.23668+03	.48858+03	.68103+01	.18966+03
3 BOTTM HOPPER ASH					.95267+03	.26022+02	.10903+04	.32621+03	.39594+03	.52738+03	.10169+03	.96059+03	.37091+00	.10698+03
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 104 - CYCLONE BOILER						
2	.02		.75	1	.30601+02	.24345+01	.16116+03	.20061+02	.51017+01	.56442+02	.27001+02	.75402+02	.10744+01	.11200+02
2	.02		.75	3	.10200+03	.48621+01	.32253+03	.32097+02	.31077+02	.70002+02	.11960+02	.15096+03	.59502-01	.10021+02
3	.02		.75	1	.25023+03	.19907+02	.13179+04	.16404+03	.42372+02	.46154+03	.22799+03	.61723+03	.87050+01	.92307+02
3	.02		.75	3	.83410+03	.39759+02	.26350+04	.26246+03	.25412+03	.64504+03	.97868+02	.12345+04	.48656+00	.14786+03
5			.75	1	.33432+03	.27713+01	.75474+02	.12913+02	.47407+01	.27713+02	.15440+02	.57195+02	.46463+00	.31251+01
5			.75	3	.11144+04	.55426+01	.15095+03	.20637+02	.28421+02	.30790+02	.33130+01	.11459+03	.25026-01	.50061+01
6	.04		.25	1	.17044+01		.22208+00	.22208+01	.87000+00	.10076+01	.20142+01	.10076+01	.26340-01	.10076+01
6	.04		.25	3	.36012+01		.44416+01	.35120+01	.51647+01	.25307+01	.87000+00	.36153+01	.14978-02	.20922+00
7	.04		.25	1	.39768+01		.51019+00	.51019+01	.20487+01	.42178+01	.46999+01	.42178+01	.61460-01	.42178+01
7	.04		.25	3	.13256+02		.10364+02	.81947+01	.12051+02	.59050+01	.20487+01	.84357+01	.34940-02	.67405+00
8	.04		.25	1	.32551+01		.60475+00	.60475+01	.27072+01	.55736+01	.62106+01	.55736+01	.81215-01	.55736+01
8	.04		.25	3	.17517+02		.13695+02	.10029+02	.15925+02	.78030+01	.27072+01	.11147+02	.46101-02	.89177+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.62609+03	.25113+02	.15959+04	.21126+03	.57929+02	.55729+03	.20424+03	.76151+03	.10494+02	.11082+03
3 BOTTM HOPPER ASH					.20870+04	.50168+02	.31375+04	.33773+03	.34676+03	.77896+03	.11070+03	.15240+04	.50150+00	.17223+03
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 105 - VERTICAL + STOKER BOILER						
1			.50	1	.29133+02	.25098+01	.82097+00	.10039+03	.30165+02	.62063+02	.10555+02	.15247+03	.90542+00	.83505+01
1			.50	3	.97109+02	.50197+01	.16748+01	.16091+03	.10108+03	.88196+02	.45177+01	.30694+03	.50197-01	.13417+02
2			.50	1	.21304+02	.16949+01	.11220+03	.13966+02	.36075+01	.39295+02	.19411+02	.52551+02	.74802+00	.78590+01
2			.50	3	.71015+02	.33050+01	.22441+03	.22346+02	.21634+02	.54910+02	.83324+01	.10510+03	.41425-01	.12546+02
3			.50	1	.21304+02	.16949+01	.11220+03	.13966+02	.36075+01	.39295+02	.19411+02	.52551+02	.74802+00	.78590+01
3			.50	3	.71015+02	.33050+01	.22441+03	.22346+02	.21636+02	.54910+02	.83324+01	.10510+03	.41425-01	.12546+02
5			.50	1	.21963+02	.10206+00	.49501+01	.84030+00	.31143+00	.10206+01	.10149+01	.37573+01	.80523-01	.20530+00
5			.50	3	.73210+02	.36411+00	.99162+01	.13557+01	.10670+01	.25400+01	.21769+00	.75146+01	.16966-02	.82048+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.93705+02	.60017+01	.23019+03	.12917+03	.37691+02	.14827+03	.50392+02	.26133+03	.24320+01	.29274+02
3 BOTTM HOPPER ASH					.31235+03	.12154+02	.46040+03	.20696+03	.22622+03	.20050+03	.21409+02	.52406+03	.13474+00	.30037+02

TABLE A-7. Continued

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	POLLUTANTS (MEGAGRAMS/YEAR) BA	BE	B	CR	CO	CU	PB	MN	HG	MO
SECTOR 1 TOTAL	.13384+05	.50613+03	.33762+05	.53406+04	.43183+04	.10430+05	.34796+04	.17261+05	.84658+02	.25521+04
BY FUEL --										
1 ANTHRACITE	.12624+03	.75295+01	.24958+01	.26130+03	.21125+03	.15106+03	.13073+02	.45881+03	.95561+00	.21768+02
2 EASTERN BITUMIN.	.40520+04	.22296+03	.14774+05	.15938+04	.11080+04	.41351+04	.12177+04	.69195+04	.34650+02	.89559+03
3 CENTRAL BITUMIN.	.34871+04	.19188+03	.12715+05	.13716+04	.95351+03	.35587+04	.10479+04	.59550+04	.29820+02	.77075+03
4 WESTERN BITUMIN.	.12673+04	.69738+02	.46207+04	.49847+03	.34652+03	.12933+04	.38084+03	.21641+04	.10837+02	.28010+03
5 LIGNITE	.24428+04	.14018+02	.38177+03	.56570+02	.55914+02	.11215+03	.31636+02	.28951+03	.02698+00	.13780+02
6 HIGH S RES. OIL	.29727+03		.18772+03	.23075+03	.24322+03	.17462+03	.11641+03	.21827+03	.11205+01	.84399+02
7 MED S RES. OIL	.74594+03		.47104+03	.57901+03	.61031+03	.43817+03	.29212+03	.54772+03	.28116+01	.21178+03
8 LOW S RES. OIL	.96504+03		.60939+03	.74909+03	.78958+03	.56688+03	.37792+03	.78860+03	.36375+01	.27399+03
BY EFFLUENT STREAMS --										
1 FLUE GAS	.30885+04	.16886+03	.10892+05	.20503+04	.62183+03	.43495+04	.24359+04	.57583+04	.80206+02	.12548+04
3 BOTTM HOPPER ASH	.10295+05	.33727+03	.22870+05	.32823+04	.36972+04	.60884+04	.10437+04	.11508+05	.44526+01	.12973+04

- -

TABLE A-7. Continued

```
                                                  POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR     BA         BE          B         CR          CO          CU          PB          MN          HG          MO

                                                   EQUIPMENT TYPE  201 - WALL FIRED W-TUBE  >29.3
        SECTOR    2 - PACKAGED BOILERS
 14         .50  1  .98775+02  .78501+01  .52021+03  .64752+02  .16726+02  .18218+03  .89995+02  .24364+03  .84601+01  .56437+02
 14         .50  3  .32925+03  .15694+02  .10404+04  .10360+03  .10031+03  .25462+03  .38632+02  .48729+03  .19206+00  .50167+02
 15         .05  1  .90473+02             .11789+02  .11789+03  .46607+02  .95956+02  .10692+03  .95956+02  .15902+01  .95936+02
 15         .05  3  .30150+03             .23578+03  .18643+03  .27416+03  .13454+03  .46607+02  .19191+03  .79586-01  .15353+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .10925+03  .78501+01  .53200+03  .18264+03  .63333+02  .27814+03  .19692+03  .33960+03  .98663+01  .13239+03
  3 BOTTM HOPPER ASH .63083+03  .15694+02  .12762+04  .29003+03  .37447+03  .38896+03  .85239+02  .67920+03  .27157+00  .73520+02

                                                   EQUIPMENT TYPE  202 - STOKER W-TUBE      >29.3
        SECTOR    2 - PACKAGED BOILERS
 14         .50  1  .98253+02  .71801+01  .47533+03  .59166+02  .15203+02  .16647+03  .82231+02  .22262+03  .81609+01  .83298+02
 14         .50  3  .30089+03  .19340+02  .95867+03  .94666+02  .91657+02  .23265+03  .35299+02  .44525+03  .17549+00  .53199+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .98253+02  .71801+01  .47533+03  .59166+02  .15203+02  .16647+03  .82231+02  .22262+03  .81609+01  .83298+02
  3 BOTTM HOPPER ASH .30089+03  .19340+02  .95867+03  .94666+02  .91657+02  .23265+03  .35299+02  .44525+03  .17549+00  .53199+02

                                                   EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29.3
        SECTOR    2 - PACKAGED BOILERS
 18              1  .84507+02             .11012+02  .11012+03  .43534+02  .89629+02  .99872+02  .89629+02  .13060+01  .89629+02
 15              3  .28169+03             .22023+03  .17414+03  .25608+03  .12548+03  .43534+02  .17926+03  .74264-01  .14391+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .84507+02             .11012+02  .11012+03  .43534+02  .89629+02  .99872+02  .89629+02  .13060+01  .89629+02
  3 BOTTM HOPPER ASH .28169+03             .22023+03  .17414+03  .25608+03  .12548+03  .43534+02  .17926+03  .74264-01  .14391+02

                                                   EQUIPMENT TYPE  204 - SCOTCH FIRETUBE     <29.3
        SECTOR    2 - PACKAGED BOILERS
 18              1  .13422+03             .17489+02  .17489+03  .69142+02  .14255+03  .15862+03  .14285+03  .20743+01  .14285+03
 15              3  .44739+03             .34978+03  .27657+03  .40672+03  .19929+03  .69142+02  .28478+03  .11795+00  .22776+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .13422+03             .17489+02  .17489+03  .69142+02  .14255+03  .15862+03  .14255+03  .20743+01  .14285+03
  3 BOTTM HOPPER ASH .44739+03             .34978+03  .27657+03  .40672+03  .19929+03  .69142+02  .28478+03  .11795+00  .22776+02

                                                   EQUIPMENT TYPE  205 - FIREBOX FIRETUBE    <29.3
        SECTOR    2 - PACKAGED BOILERS
 18              1  .86496+02             .11271+02  .11271+03  .44558+02  .91738+02  .10222+03  .91738+02  .13860+01  .91738+02
 15              3  .28032+03             .22941+03  .17825+03  .26211+03  .12843+03  .44558+02  .10348+03  .76012-01  .14678+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .86496+02             .11271+02  .11271+03  .44558+02  .91738+02  .10222+03  .91738+02  .13860+01  .91738+02
  3 BOTTM HOPPER ASH .28032+03             .22941+03  .17825+03  .26211+03  .12843+03  .44558+02  .10348+03  .76012-01  .14678+02

                                                   EQUIPMENT TYPE  206 - STOKER FIRED W-TUBE <100
        SECTOR    2 - PACKAGED BOILERS
  1         .15  1  .56127+01  .48355+00  .15017+00  .19342+02  .58116+01  .12111+02  .20336+01  .29374+02  .17444+00  .16080+01
  1         .15  3  .10709+02  .96709+00  .32266+00  .31001+02  .34008+02  .16992+02  .87030+00  .59020+02  .96709-02  .25049+01
 14         .15  1  .29691+03  .23621+02  .15637+04  .19464+03  .50276+02  .54763+03  .27051+03  .73287+03  .10925+02  .10953+04
 14         .15  3  .98969+03  .47175+02  .31274+04  .31142+04  .30152+03  .76536+03  .11612+03  .14647+04  .57732+00  .17404+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS        .30252+03  .24104+02  .15639+04  .21398+03  .56088+02  .55974+03  .27255+03  .76174+03  .10599+02  .11113+03
  3 BOTTM HOPPER ASH .10004+04  .48142+02  .31277+04  .34292+03  .33641+03  .78235+03  .11699+03  .15238+04  .58699+00  .17743+03
```

TABLE A-7. Continued

```
                                                                  POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR      BA          BE          B           CR          CO          CU          PB          MN          MG          MO

                                                       EQUIPMENT TYPE  208 - CAST IRON BOILERS
          SECTOR    2 - PACKAGED BOILERS
 15                  1  .27696+02              .36088+01   .36088+02   .14267+02   .29374+02   .32731+02   .29374+02   .42002+00   .29374+02
 15                  3  .92319+02              .72177+02   .57070+02   .83926+02   .41124+02   .14267+02   .58749+02   .24339-01   .46999+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .27696+02              .36088+01   .36088+02   .14267+02   .29374+02   .32731+02   .29374+02   .42002+00   .29374+02
  3 BOTTM HOPPER ASH    .92319+02              .72177+02   .57070+02   .83926+02   .41124+02   .14267+02   .58749+02   .24339-01   .46999+01

                                                       EQUIPMENT TYPE  209 - STOKER F-T BOILER  <29.3
          SECTOR    2 - PACKAGED BOILERS
  1          .15     1  .11225+02   .96709+00  .31634+00   .38684+02   .11623+02   .24222+02   .40672+01   .58749+02   .34888+00   .32176+01
  1          .15     3  .37418+02   .19342+01  .64533+00   .62002+02   .69775+02   .33984+02   .17408+01   .11804+03   .19342-01   .51699+01
 14          .15     1  .10768+03   .85669+01  .56714+03   .70593+02   .18235+02   .19862+03   .98112+02   .26562+03   .37889+01   .39728+02
 14          .15     3  .35895+03   .17110+02  .11343+04   .11295+03   .10936+03   .27759+03   .42116+02   .53124+03   .20939+00   .63419+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .11891+03   .95340+01  .56745+03   .10928+03   .29858+02   .22284+03   .10218+03   .32457+03   .41298+01   .42991+02
  3 BOTTM HOPPER ASH    .39637+03   .19044+02  .11349+04   .17495+03   .17913+03   .31157+03   .43857+02   .64920+03   .22073+00   .68504+02

                                                       EQUIPMENT TYPE  210 - HRT BOILERS   <29.3 MJ/S
          SECTOR    2 - PACKAGED BOILERS
 15                  1  .52551+02              .68475+01   .68475+02   .27072+02   .55736+02   .62106+02   .55736+02   .81215+00   .55736+02
 15                  3  .17517+03              .13695+03   .10829+03   .15925+03   .78030+02   .27072+02   .11147+03   .46101-01   .89177+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .52551+02              .68475+01   .68475+02   .27072+02   .55736+02   .62106+02   .55736+02   .81215+00   .55736+02
  3 BOTTM HOPPER ASH    .17517+03              .13695+03   .10829+03   .15925+03   .78030+02   .27072+02   .11147+03   .46101-01   .89177+01

                                                       EQUIPMENT TYPE  211 - RLS/COMM STEAM + HOT WA!
          SECTOR    2 - PACKAGED BOILERS
  1                  1  .37418+01   .32236+00  .10545+00   .12895+02   .38744+01   .80742+01   .13557+01   .19503+02   .11629+00   .10725+01
  1                  3  .12473+02   .64473+00  .21511+00   .20667+02   .23258+02   .11328+02   .58029+00   .39346+02   .64473-02   .17253+01
 14                  1  .21304+01   .16949+00  .11220+02   .13966+01   .36075+00   .39295+01   .19411+01   .52551+01   .74002-01   .70590+00
 14                  3  .71015+01   .33850+00  .22441+02   .22346+01   .21636+01   .54918+01   .83324+00   .10510+02   .41425-02   .12546+01
 15                  1  .98000+01              .12770+01   .12770+02   .50485+01   .10394+02   .11582+02   .10394+02   .15145+00   .10394+02
 15                  3  .32667+02              .25539+02   .20194+02   .29697+02   .14552+02   .50485+01   .20780+02   .86121-02   .16630+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .15672+02   .49185+00  .12603+02   .27061+02   .92036+01   .22398+02   .14079+02   .35232+02   .84255+00   .12252+02
  3 BOTTM HOPPER ASH    .52241+02   .98323+00  .48195+02   .43096+02   .55119+02   .31371+02   .64620+01   .70645+02   .19202-01   .46409+01
```

TABLE A-7. Continued

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	POLLUTANTS (MEGAGRAMS/YEAR) BA	BE	B	CR	CO	CU	PB	MN	HG	MO
SECTOR 2 TOTAL	.47756+04	.14737+03	.10744+05	.28339+04	.25773+04	.39777+04	.16107+04	.62702+04	.38685+02	.11956+04
BY FUEL --										
1 ANTHRACITE	.89100+02	.53190+01	.17631+01	.18459+03	.14923+03	.10671+03	.10640+02	.32411+03	.67507+00	.19377+02
14 BIT/LIG COAL	.25816+04	.14205+03	.94120+04	.10154+04	.70590+03	.26345+04	.77580+03	.44005+04	.22076+02	.57859+03
15 RESIDUAL OIL	.21049+04		.13292+04	.16339+04	.17222+04	.12364+04	.82429+03	.15455+04	.79838+01	.59761+03
BY EFFLUENT STREAMS --										
1 FLUE GAS	.11021+04	.49160+02	.32015+04	.10944+04	.37242+03	.16584+04	.11243+04	.20924+04	.29864+02	.79804+03
3 BOTTM HOPPER ASH	.36736+04	.98204+02	.75423+04	.17395+04	.22049+04	.23193+04	.48643+03	.41850+04	.16207+01	.44274+03

- -

TABLE A-7. Concluded

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	BA	BE	B	CR	CO	CU	PB	MN	HG	MO
	POLLUTANTS (MEGAGRAMS/YEAR)									
GRAND TOTAL	.10159+05	.65350+03	.44506+05	.81744+04	.68956+04	.14408+05	.50983+04	.23540+05	.11534+03	.87357+04
BY FUEL --										
1 ANTHRACITE	.21542+03	.12848+02	.42588+01	.44589+03	.36048+03	.25777+03	.25721+02	.78292+03	.16307+01	.37145+02
2 EASTERN BITUMIN.	.40520+04	.22296+03	.14774+05	.15938+04	.11080+04	.41351+04	.12177+04	.69175+04	.84650+02	.89559+04
3 CENTRAL BITUMIN.	.34871+04	.19188+03	.12715+05	.13716+04	.95351+03	.35587+04	.10479+04	.59550+04	.29820+02	.77075+04
4 WESTERN BITUMIN.	.12673+04	.69734+02	.46207+04	.49847+03	.34652+03	.12933+04	.38084+03	.21641+04	.10837+02	.28810+04
5 LIGNITE	.24428+04	.14018+02	.38177+03	.56570+02	.55914+02	.11215+03	.31636+02	.28931+03	.82698+00	.13788+02
6 HIGH S RES. OIL	.29727+03		.18772+03	.23075+03	.24322+03	.17462+03	.11641+03	.21827+03	.11205+01	.84399+02
7 MED S RES. OIL	.74594+03		.47104+03	.57901+03	.61031+03	.43817+03	.29212+03	.54772+03	.28116+01	.21178+04
8 LOW S RES. OIL	.96504+03		.60759+03	.74909+03	.78958+03	.56688+03	.37792+03	.78860+03	.36375+01	.27399+04
14 BIT/LIG COAL	.25816+04	.14205+03	.94128+04	.10154+04	.70598+03	.26345+04	.77580+03	.44885+04	.22076+02	.57859+04
15 RESIDUAL OIL	.21049+04		.13292+04	.16339+04	.17222+04	.12364+04	.82429+03	.15455+04	.79358+01	.59761+04

TABLE A-8. EMISSION INVENTORY — GROUP III POLLUTANTS

FUEL TYPE	-CNTRL FAC- 1	2	3	EFF STR	NI	V	ZN	ZR	AS	HI	AL	SB	CD	SE
								POLLUTANTS (MEGAGRAMS/YEAR)						
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 101 - TANGENTIAL BOILERS						
2			.65	1	.92515+03	.93510+03	.73408+04	.67074+03	.35010+03	.23490+02	.23039+06	.31622+02	.95317+02	.13100+03
2			.65	3	.63018+03	.93510+03	.73408+04	.40769+04	.35010+03	.32977+02	.57597+06	.37946+02	.54435+02	.20121+02
3			.65	1	.31701+03	.56448+03	.44313+04	.40973+03	.21134+03	.14180+02	.13908+06	.19089+02	.57539+02	.79082+02
3			.65	3	.38041+03	.56448+03	.44313+04	.24611+04	.21134+03	.19907+02	.34769+06	.22946+02	.32060+02	.16975+02
4			.65	1	.17391+03	.30960+03	.24311+04	.22470+03	.11594+03	.77794+01	.76298+05	.10472+02	.31566+02	.43305+02
4			.65	3	.20870+03	.30960+03	.24311+04	.13502+04	.11594+03	.10921+02	.19075+06	.12567+02	.10027+02	.93129+01
5			.65	1	.51324+01	.13606+02	.41972+02	.22011+02	.57027+01	.11405+01	.42428+04	.28513+00	.19959+00	.25776+01
5			.65	3	.61589+01	.13686+02	.41972+02	.13686+03	.57027+01	.15968+01	.10607+05	.34216+00	.11405+00	.55430+03
6	.01		.25	1	.16871+04	.25307+04	.46396+02	.92793+01	.23620+00		.72547+03	.23620+00	.32099+00	.33743+02
6	.01		.25	3	.16871+04	.25307+04	.46396+02	.55676+02	.23620+00		.16871+04	.27830+00	.10559+01	.72547+01
7	.01		.25	1	.42351+04	.63526+04	.11646+03	.23293+02	.59291+00		.10211+04	.59291+00	.82584+00	.84781+02
7	.01		.25	3	.42351+04	.63526+04	.11646+03	.13976+03	.59291+00		.42351+04	.69878+00	.46586+01	.10211+02
8	.01		.25	1	.54746+04	.82119+04	.15055+03	.30110+02	.76644+00		.23541+04	.76644+00	.10675+01	.10949+03
8	.01		.25	3	.54746+04	.82119+04	.15055+03	.10066+03	.76644+00		.54746+04	.90331+00	.60220+01	.23541+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.12410+05	.10910+05	.14559+05	.13987+04	.68468+03	.46591+02	.45490+06	.63063+02	.10684+03	.48390+03
3 BOTTM HOPPER ASH					.12622+05	.10910+05	.14559+05	.84012+04	.68468+03	.65402+02	.11364+07	.75642+02	.11797+03	.35534+03
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 102 - WALL FIRED BOILER						
2			.65	1	.30280+03	.53910+03	.42327+04	.39136+03	.20187+03	.13545+02	.13284+06	.10253+02	.54960+02	.75537+02
2			.65	3	.46336+03	.53910+03	.42327+04	.23508+04	.20187+03	.19015+02	.33210+06	.21088+02	.31387+02	.16214+02
3			.65	1	.10292+03	.32572+03	.25570+04	.23642+03	.12195+03	.81023+01	.80249+05	.11015+02	.33201+02	.45632+02
3			.65	3	.21951+03	.32572+03	.25570+04	.14201+04	.12195+03	.11487+02	.20062+06	.13218+02	.10961+02	.97951+01
4			.65	1	.10027+03	.17054+03	.14016+04	.12959+03	.66044+02	.44850+01	.43908+05	.60375+01	.10199+02	.25013+02
4			.65	3	.12032+03	.17054+03	.14016+04	.77841+03	.66044+02	.62963+01	.10997+06	.72450+01	.10393+02	.53691+01
5			.65	1	.10652+01	.20406+01	.87111+01	.47343+01	.11836+01	.23672+00	.88050+03	.59179-01	.41425-01	.53498+00
5			.65	3	.12703+01	.20406+01	.87111+01	.20406+02	.11836+01	.33140+00	.22015+04	.71015-01	.23672-01	.11504+03
6	.05		.25	1	.16871+04	.25307+04	.46396+02	.92793+01	.23620+00		.72547+03	.23620+00	.32099+00	.33743+02
6	.05		.25	3	.16871+04	.25307+04	.46396+02	.55676+02	.23620+00		.16871+04	.27830+00	.10559+01	.72547+01
7	.05		.25	1	.42437+04	.63655+04	.11670+03	.23340+02	.59411+00		.10240+04	[illegible]	.82751+00	.84873+02
7	.05		.25	3	.42437+04	.63655+04	.11670+03	.14004+03	.59411+00		.42437+04	.70020+00	.46690+01	.10240+02
8	.05		.25	1	.54832+04	.82248+04	.15079+03	.30150+02	.76765+00		.23570+04	.76765+00	.10692+01	.10966+03
8	.05		.25	3	.54832+04	.82248+04	.15079+03	.10095+03	.76765+00		.54832+04	.90473+00	.60315+01	.23570+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --														
1 FLUE GAS					.12081+05	.10167+05	.85130+04	.82480+03	.39344+03	.26449+02	.26287+06	.36992+02	.10863+03	.37800+03
3 BOTTM HOPPER ASH					.12110+05	.10167+05	.85130+04	.49543+04	.39344+03	.37129+02	.65631+06	.44297+02	.73320+02	.11585+03
SECTOR 1 - UTILITY BOILERS								EQUIPMENT TYPE 103 - OPPOSED WALL BOILER						
2			.65	1	.84656+02	.15074+03	.11034+04	.10942+03	.56437+02	.37060+01	.37139+05	.50976+01	.15366+02	.21110+02
2			.65	3	.10159+03	.15074+03	.11034+04	.65722+03	.56437+02	.53160+01	.92040+05	.61171+01	.87751+01	.45332+01
3			.65	1	.51034+02	.90073+02	.71337+03	.65960+02	.34022+02	.22828+01	.22389+05	.30730+01	.92629+01	.12751+02
3			.65	3	.61240+02	.90073+02	.71337+03	.39620+03	.34022+02	.32047+01	.55972+05	.36076+01	.52099+01	.27320+01
4			.65	1	.28019+02	.49891+02	.39166+03	.36213+02	.18679+02	.12533+01	.12292+05	.16871+01	.50055+01	.69096+01
4			.65	3	.33622+02	.49891+02	.39166+03	.21752+03	.18679+02	.17594+01	.30730+05	.20246+01	.29043+01	.15003+01
5			.65	1	.20336+01	.54229+01	.16630+02	.90302+01	.22596+01	.45191+00	.16811+04	.11298+00	.79085-01	.10213+01
5			.65	3	.24403+01	.54229+01	.16630+02	.54229+02	.22596+01	.63260+00	.42020+04	.13557+00	.45191-01	.21963+03
6	.05		.25	1	.68002+03	.10200+04	.18701+02	.37401+01	.95203-01		.29241+03	.95203-01	.13260+00	.13600+02
6	.05		.25	3	.68002+03	.10200+04	.18701+02	.22441+02	.95203-01		.68002+03	.11220+00	.74802+00	.29241+01

TABLE A-8. Continued

```
FUEL -CNTRL FAC- EFF                                          POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NI         V          ZN         ZR         AS         BI         AL         SB         CD         SE

  7  .05     .25  1   .17130+04  .25694+04  .47106+02  .94213+01  .23981+00             .73657+03  .23981+00  .33403+00  .34259+02
  7  .05     .25  3   .17130+04  .25694+04  .47106+02  .56528+02  .23981+00             .17130+04  .28264+00  .10043+01  .73657+01
  8  .05     .25  1   .22208+04  .33312+04  .61073+02  .12215+02  .31092+00             .95495+03  .31092+00  .43306+00  .44416+02
  8  .05     .25  3   .22208+04  .33312+04  .61073+02  .73287+02  .31092+00             .22208+04  .36644+00  .24429+01  .95495+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .47795+04  .72176+04  .24319+04  .24600+03  .11204+03  .77748+01  .75485+05  .10617+02  .30693+02  .13419+03
  3 BOTTM HOPPER ASH  .48127+04  .72176+04  .24319+04  .14774+04  .11204+03  .10913+02  .18837+06  .12726+02  .22090+02  .21992+05

         SECTOR    1 - UTILITY BOILERS                   EQUIPMENT TYPE  104 - CYCLONE BOILER
  2  .02     .75  1   .31621+02  .56306+02  .44201+03  .40869+02  .21081+02  .14144+01  .13872+05  .19041+01  .57394+01  .78882+01
  2  .02     .75  3   .37945+02  .56306+02  .44201+03  .24549+03  .21081+02  .19857+01  .34681+05  .22049+01  .32777+01  .16932+01
  3  .02     .75  1   .25857+03  .46042+03  .36144+04  .33420+03  .17238+03  .11566+02  .11344+06  .15570+02  .46932+02  .64504+02
  3  .02     .75  3   .31029+03  .46042+03  .36144+04  .20074+04  .17238+03  .16237+02  .28559+06  .18684+02  .26802+02  .13846+02
  5          .75  1   .13267+02  .35378+02  .10849+03  .58964+02  .14741+02  .29482+01  .10967+05  .73705+00  .52593+00  .66629+01
  5          .75  3   .15920+02  .35378+02  .10849+03  .35378+03  .14741+02  .41275+01  .27418+05  .88446+00  .29482+00  .14328+06
  6  .04     .25  1   .10329+03  .15494+03  .28406+01  .56812+00  .14461-01             .44416+02  .14461-01  .20142-01  .20659+01
  6  .04     .25  3   .10329+03  .15494+03  .28406+01  .34087+01  .14461-01             .10329+03  .17044-01  .11362+00  .44416+00
  7  .04     .25  1   .24102+03  .36153+03  .66280+01  .13256+01  .33743-01             .10364+03  .33743-01  .46999-01  .40204+01
  7  .04     .25  3   .24102+03  .36153+03  .66280+01  .79536+01  .33743-01             .24102+03  .39766-01  .26512+00  .10364+01
  8  .04     .25  1   .31849+03  .47774+03  .87585+01  .17517+01  .44589-01             .13695+03  .44589-01  .62106-01  .63698+01
  8  .04     .25  3   .31849+03  .47774+03  .87585+01  .10510+02  .44589-01             .31849+03  .52551-01  .35034+00  .13695+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .96626+03  .15463+04  .41832+04  .43767+03  .20829+03  .15929+02  .13856+06  .18304+02  .53817+02  .92311+02
  3 BOTTM HOPPER ASH  .10270+04  .15463+04  .41832+04  .26285+04  .20829+03  .22550+02  .34636+06  .21963+02  .31184+02  .14530+06

         SECTOR    1 - UTILITY BOILERS                   EQUIPMENT TYPE  105 - VERTICAL + STOKER BOILER
  1          .50  1   .41846+02  .13089+02  .27679+02  .16091+02  .83505+01  .83505-01             .83505-01  .11728+00  .46913+00
  1          .50  3   .50197+02  .13089+02  .27679+02  .96640+02  .83505+01  .11728+00             .10039+00  .67085-01  .10039+00
  2          .50  1   .22015+02  .39200+02  .30773+03  .28453+02  .14676+02  .98474+00  .96588+04  .13256+01  .39958+01  .54918+01
  2          .50  3   .26417+02  .39200+02  .30773+03  .17091+03  .14676+02  .13824+01  .24145+05  .15907+01  .22819+01  .11788+01
  3          .50  1   .22015+02  .39200+02  .30773+03  .28453+02  .14676+02  .98474+00  .96588+04  .13256+01  .39958+01  .54918+01
  3          .50  3   .26417+02  .39200+02  .30773+03  .17091+03  .14676+02  .13824+01  .24145+05  .15907+01  .22819+01  .11788+01
  5          .50  1   .87154+00  .23241+01  .71273+01  .38735+01  .96838+00  .19368+00  .72048+03  .48419-01  .33893-01  .43771+00
  5          .50  3   .10459+01  .23241+01  .71273+01  .23241+02  .96838+00  .27115+00  .18012+04  .58108-01  .19368-01  .94127+00
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .86747+02  .93813+02  .65827+03  .76871+02  .38672+02  .22467+01  .20836+05  .27831+01  .81427+01  .11898+02
  3 BOTTM HOPPER ASH  .10408+03  .93813+02  .65827+03  .46178+03  .38672+02  .51533+01  .50891+05  .33408+01  .46503+01  .94151+04
```

TABLE A-8. Continued

```
FUEL -CNTRL FAC- EFF                                         POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR       NI          V          ZN          ZR          AS          BI          AL          SU          CD          SE

SECTOR    1 TOTAL
                       .60936+05  .91086+05  .60675+05  .20907+05  .28743+04  .23794+03  .33294+07  .28960+03  .63676+03  .29292+06

  BY FUEL --
 1 ANTHRACITE          .92043+02  .26177+02  .95357+02  .11273+03  .16701+02  .20079+00              .18390+00  .10437+00  .56952+00
 2 EASTERN BITUMIN.    .21257+04  .34411+04  .27013+05  .87502+04  .12083+04  .10390+03  .14836+07  .12000+03  .27553+03  .29278+03
 3 CENTRAL BITUMIN.    .10294+04  .29614+04  .23240+05  .75304+04  .11087+04  .89414+02  .12768+07  .11016+03  .23713+03  .25197+03
 4 WESTERN BITUMIN.    .66404+03  .10762+04  .84486+04  .27367+04  .40293+03  .32495+02  .46402+06  .40053+02  .86176+02  .91570+02
 5 LIGNITE             .49213+02  .11930+03  .36587+03  .69594+03  .49710+02  .11930+02  .64723+05  .27341+01  .13670+01  .24160+06
 6 HIGH S RES. OIL     .83152+04  .12473+05  .22867+03  .16007+03  .11641+01              .59453+04  .12681+01  .53041+01  .10103+03
 7 MED  S RES. OIL     .20065+05  .31298+05  .57380+03  .40166+03  .29212+01              .14919+05  .31820+01  .13510+02  .25351+03
 8 LOW  S RES. OIL     .26994+05  .40491+05  .74234+03  .51964+03  .37792+01              .19301+05  .41146+01  .17479+02  .32798+03

  BY EFFLUENT STREAMS --
 1 FLUE GAS            .30292+05  .45943+05  .30330+05  .29042+04  .14371+04  .90909+02  .95103+06  .13171+03  .38762+03  .10972+04
 2 BOTTM HOPPER ASH    .30604+05  .45943+05  .30338+05  .17923+05  .14371+04  .13095+03  .23775+07  .15797+03  .24914+03  .24103+06

      - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-8. Continued

```
FUEL -CNTRL FAC- EFF                                     POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NI          V          ZN          ZR          AS          BI          AL          SN          CD          SE

           SECTOR    2 - PACKAGED BOILERS                EQUIPMENT TYPE  201 - WALL FIRED W-TUBE  >29.3
 19         .50   1   .10207+03  .18175+03  .14267+04  .13192+03  .68045+02  .45656+01  .44778+05  .61460+01  .18926+02  .29462+02
 19         .50   3   .12248+03  .18175+03  .14267+04  .79239+03  .68045+02  .64094+01  .11194+06  .73752+01  .10580+02  .54655+01
 15         .05   1   .54832+04  .82248+04  .15079+03  .30158+02  .76765+00              .23578+04  .76765+00  .10692+01  .10566+03
 15         .05   3   .54832+04  .82248+04  .15079+03  .18095+03  .76765+00              .54832+04  .90473+00  .60315+01  .23578+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .55853+04  .84065+04  .15775+04  .16208+03  .68813+02  .45656+01  .47136+05  .69136+01  .19995+02  .13513+03
  3 BOTTM HOPPER ASH  .56057+04  .84065+04  .15775+04  .97334+03  .68813+02  .64094+01  .11743+06  .82799+01  .16611+02  .29043+02

           SECTOR    2 - PACKAGED BOILERS                EQUIPMENT TYPE  202 - STOKER W-TUBE      >29.3
 19         .50   1   .93262+02  .16607+03  .13037+04  .12054+03  .62174+02  .41717+01  .40915+05  .56150+01  .16927+02  .28265+02
 19         .50   3   .11191+03  .16607+03  .13037+04  .72403+03  .62174+02  .50564+01  .10229+06  .67309+01  .96671+01  .49990+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .93262+02  .16607+03  .13037+04  .12054+03  .62174+02  .41717+01  .40915+05  .56150+01  .16927+02  .28265+02
  3 BOTTM HOPPER ASH  .11191+03  .16607+03  .13037+04  .72403+03  .62174+02  .50564+01  .10229+06  .67309+01  .96671+01  .49990+01

           SECTOR    2 - PACKAGED BOILERS                EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29.3
 15               1   .51217+04  .76025+04  .14085+03  .20169+02  .71703+00              .22023+04  .71703+00  .99072+00  .10243+03
 15               3   .51217+04  .76025+04  .14085+03  .16901+03  .71703+00              .51217+04  .84507+00  .56330+01  .22023+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .51217+04  .76025+04  .14085+03  .20169+02  .71703+00              .22023+04  .71703+00  .99072+00  .10243+03
  3 BOTTM HOPPER ASH  .51217+04  .76025+04  .14085+03  .16901+03  .71703+00              .51217+04  .84507+00  .56330+01  .22023+02

           SECTOR    2 - PACKAGED BOILERS                EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29.3
 15               1   .81344+04  .12202+05  .22370+03  .44739+02  .11300+01              .34970+04  .11300+01  .15062+01  .16269+03
 15               3   .81344+04  .12202+05  .22370+03  .26844+03  .11300+01              .81344+04  .13422+01  .89470+01  .34970+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .81344+04  .12202+05  .22370+03  .44739+02  .11300+01              .34970+04  .11300+01  .15062+01  .16269+03
  3 BOTTM HOPPER ASH  .81344+04  .12202+05  .22370+03  .26844+03  .11300+01              .81344+04  .13422+01  .89470+01  .34970+02

           SECTOR    2 - PACKAGED BOILERS                EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29.3
 15               1   .52422+04  .78633+04  .14416+03  .20832+02  .73390+00              .22541+04  .73390+00  .10222+01  .10484+03
 15               3   .52422+04  .78633+04  .14416+03  .17299+03  .73390+00              .52422+04  .86496+00  .57664+01  .22541+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .52422+04  .78633+04  .14416+03  .20832+02  .73390+00              .22541+04  .73390+00  .10222+01  .10484+03
  3 BOTTM HOPPER ASH  .52422+04  .78633+04  .14416+03  .17299+03  .73390+00              .52422+04  .86496+00  .57664+01  .22541+02

           SECTOR    2 - PACKAGED BOILERS                EQUIPMENT TYPE  206 - STOKER FIRED W-TUBE <100
  1         .15   1   .80621+01  .25217+01  .53326+01  .31001+01  .16000+01  .16000-01              .16000-01  .22596-01  .90302-01
  1         .15   3   .96709+01  .25217+01  .53326+01  .10619+02  .16000+01  .22596-01              .19342-01  .12925-01  .19342-01
 19         .15   1   .30600+03  .54631+03  .42886+04  .39653+03  .20454+03  .13724+02  .13460+06  .10474+02  .55686+02  .76536+02
 19         .15   3   .36816+03  .54631+03  .42886+04  .23810+04  .20454+03  .19266+02  .33649+06  .22149+02  .31002+02  .16429+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS          .31406+03  .54883+03  .42940+04  .39963+03  .20614+03  .13740+02  .13460+06  .10490+02  .55709+02  .76626+02
  3 BOTTM HOPPER ASH  .37783+03  .54883+03  .42940+04  .24805+04  .20614+03  .19288+02  .33649+06  .22168+02  .31015+02  .16448+02
```

TABLE A-8. Continued

```
FUEL -CNTRL FAC- EFF                                       POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NI          V          ZN          ZR          AS          BI          AL          SN          CD          SE

        SECTOR    2 - PACKAGED BOILERS                    EQUIPMENT TYPE  208 - CAST IRON BOILERS
 15                  1  .16785+04  .25170+04  .96160+02  .92319+01  .23499+00                          .72177+03  .23499+00  .32731+00  .38571+02
 19                  3  .16785+04  .25170+04  .96160+02  .55391+02  .23499+00                          .16785+04  .27696+00  .10464+01  .72177+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .16785+04  .25170+04  .96160+02  .92319+01  .23499+00                          .72177+03  .23499+00  .32731+00  .38571+02
  3 BOTTM HOPPER ASH    .16785+04  .25170+04  .96160+02  .55391+02  .23499+00                          .16785+04  .27696+00  .10464+01  .72177+01

        SECTOR    2 - PACKAGED BOILERS                    EQUIPMENT TYPE  209 - STOKER F-T BOILER  <29.3
  1          .15     1  .16124+02  .50933+01  .10665+02  .62002+01  .32176+01  .32176-01             .32176-01  .45191-01  .10076+00
  1          .15     3  .19342+02  .50933+01  .10665+02  .37230+02  .32176+01  .45191-01             .30604-01  .25049-01  .30604-01
 14          .15     1  .11127+03  .19814+03  .15554+04  .14302+03  .74102+02  .49774+01  .40017+05  .67043+01  .20197+02  .27759+02
 14          .15     3  .13353+03  .19814+03  .15554+04  .86307+03  .74102+02  .69075+01  .12204+06  .88484+01  .11534+02  .99585+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .12740+03  .20310+03  .15661+04  .15002+03  .77400+02  .50096+01  .40017+05  .67825+01  .20292+02  .27939+02
  3 BOTTM HOPPER ASH    .15287+03  .20310+03  .15661+04  .90110+03  .77400+02  .70327+01  .12204+06  .88791+01  .11560+02  .99972+01

        SECTOR    2 - PACKAGED BOILERS                    EQUIPMENT TYPE  210 - HRT BOILERS   <29.3 MJ/S
 19                  1  .31049+04  .47774+04  .87505+02  .17517+02  .44509+00                          .13695+04  .44509+00  .62106+00  .63690+02
 15                  3  .31049+04  .47774+04  .87505+02  .10510+03  .44509+00                          .31049+04  .52551+00  .35034+01  .13695+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .31049+04  .47774+04  .87505+02  .17517+02  .44509+00                          .13695+04  .44509+00  .62106+00  .63690+02
  3 BOTTM HOPPER ASH    .31049+04  .47774+04  .87505+02  .10510+03  .44509+00                          .31049+04  .52551+00  .35034+01  .13695+02

        SECTOR    2 - PACKAGED BOILERS                    EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
  1                  1  .33797+01  .16011+01  .35950+01  .20667+01  .10725+01  .10725-01             .10725-01  .15064-01  .60253-01
  1                  3  .64473+01  .16011+01  .35950+01  .12413+02  .10725+01  .15064-01             .12095-01  .06164-02  .12095-01
 14                  1  .22015+01  .39200+01  .30773+02  .20455+01  .14676+01  .98474-01  .96500+03  .13256+00  .39950+00  .94910+00
 14                  3  .26417+01  .39200+01  .30773+02  .17091+02  .14676+01  .13029+00  .24145+04  .15907+00  .22019+00  .11700+00
 15                  1  .59394+03  .09091+03  .16333+02  .32667+01  .03152-01             .25589+03  .03152-01  .11502+00  .11079+00
 15                  3  .59394+03  .09091+03  .16333+02  .19600+02  .03152-01             .59394+03  .90000-01  .65334+00  .25589+01
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS            .60152+03  .09651+03  .50661+02  .01707+01  .26233+01  .10920+00  .12212+04  .22644+00  .50091+00  .12900+02
  3 BOTTM HOPPER ASH    .60303+03  .09651+03  .50661+02  .49103+02  .26233+01  .15331+00  .30004+04  .26997+00  .09015+00  .26047+01
```

TABLE A-8. Continued

```
FUEL -CNTRL FAC- EFF                                          POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR      NI          V          ZN          ZR          AS          BI          AL          SB          CD          SE

SECTOR    2 TOTAL
                      .60297+05  .90527+05  .18869+05  .67879+04  .84085+03  .66336+02  .98735+06  .90660+02  .21380+03  .90230+03

  BY FUEL --
 1 ANTHRACITE         .65021+02  .10492+02  .39105+02  .79636+02  .11798+02  .14104+00              .12991+00  .13024+00  .40232+00
14 BIT/LIG COAL       .13543+04  .21924+04  .17211+05  .55749+04  .82081+03  .66194+02  .94525+06  .81551+02  .17555+03  .18654+03
15 RESIDUAL OIL       .58878+05  .88316+05  .16191+04  .11334+04  .82429+01              .42097+05  .89780+01  .38123+02  .71536+03

  BY EFFLUENT STREAMS --
 1 FLUE GAS           .30084+05  .45264+05  .94344+04  .96894+03  .42042+03  .27596+02  .28273+06  .41249+02  .11756+03  .74268+03
 3 BOTTM HOPPER ASH   .30213+05  .45264+05  .94344+04  .58190+04  .42042+03  .38740+02  .70462+06  .49411+02  .96241+02  .15962+03

      - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-8. Concluded

FUEL -CNTRL FAC- EFF TYPE 1 2 3 STR	POLLUTANTS (MEGAGRAMS/YEAR) NI	V	ZN	ZR	AS	BI	AL	SB	CD	SE
GRAND TOTAL	.12123+06	.18241+06	.79544+05	.27695+05	.37151+04	.30427+03	.43167+07	.88034+03	.85056+03	.24382+04
BY FUEL --										
1 ANTHRACITE	.15706+03	.44670+02	.94462+02	.19237+03	.28499+02	.34263+00		.31301+00	.31461+00	.97104+00
2 EASTERN BITUMIN.	.21257+04	.34411+04	.27013+05	.87502+04	.12883+04	.10390+03	.14036+07	.12800+03	.27553+03	.29270+03
3 CENTRAL BITUMIN.	.10294+04	.29619+04	.23248+05	.75304+04	.11087+04	.89414+02	.12768+07	.11016+03	.23713+03	.25197+03
4 WESTERN BITUMIN.	.66484+03	.10762+04	.84486+04	.27367+04	.40293+03	.32495+02	.46402+06	.40035+02	.86176+02	.91570+02
5 LIGNITE	.49213+02	.11930+03	.36587+03	.69594+03	.49710+02	.11930+02	.64725+05	.27341+01	.13670+01	.24160+00
6 HIGH S RES. OIL	.83152+04	.12473+05	.22867+03	.16007+03	.11641+01		.59453+04	.12681+01	.53841+01	.10103+03
7 MED S RES. OIL	.20865+05	.31298+05	.57380+03	.40166+03	.29212+01		.14919+05	.31020+01	.13510+02	.25351+03
8 LOW S RES. OIL	.26994+05	.40491+05	.74234+03	.51964+03	.37792+01		.19801+05	.41166+01	.17479+02	.32798+03
14 BIT/LIG COAL	.13543+04	.21924+04	.17211+05	.55749+04	.82081+03	.66194+02	.94525+06	.81551+02	.17555+03	.10659+04
15 RESIDUAL OIL	.58870+05	.80316+05	.16191+04	.11334+04	.82429+01		.42097+05	.89788+01	.30123+02	.71586+03

TABLE A-9. EMISSION INVENTORY — GROUP IV POLLUTANTS

```
FUEL -CNTRL FAC- EFF                                         POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR        P          SR


          SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  101 - TANGENTIAL BOILERS
  6  .01       .25   1                .11810+01
  6  .01       .25   3   .22776+01  .72547+02
  7  .01       .25   1                .29645+01
  7  .01       .25   3   .57173+01  .18211+03
  8  .01       .25   1                .38322+01
  8  .01       .25   3   .73907+01  .23541+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .79777+01
  3 BOTTM HOPPER ASH   .15386+02  .49006+03

          SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  102 - WALL FIRED BOILER
  6  .05       .25   1                .11810+01
  6  .05       .25   3   .22776+01  .72547+02
  7  .05       .25   1                .29706+01
  7  .05       .25   3   .57289+01  .18248+03
  8  .05       .25   1                .38382+01
  8  .05       .25   3   .74023+01  .23578+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .79898+01
  3 BOTTM HOPPER ASH   .15409+02  .49080+03

          SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  103 - OPPOSED WALL BOILER
  6  .05       .25   1                .47601+00
  6  .05       .25   3   .91803+00  .29241+02
  7  .05       .25   1                .11991+01
  7  .05       .25   3   .23125+01  .73657+02
  8  .05       .25   1                .15546+01
  8  .05       .25   3   .29981+01  .95495+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .32297+01
  3 BOTTM HOPPER ASH   .62286+01  .19839+03

          SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  104 - CYCLONE BOILER
  6  .04       .25   1                .72306-01
  6  .04       .25   3   .13945+00  .44416+01
  7  .04       .25   1                .16871+00
  7  .04       .25   3   .32538+00  .10364+02
  8  .04       .25   1                .22294+00
  8  .04       .25   3   .42996+00  .13695+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .46396+00
  3 BOTTM HOPPER ASH   .89478+00  .28501+02

          SECTOR    1 - UTILITY BOILERS                     EQUIPMENT TYPE  105 - VERTICAL + STOKER BOILER
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
```

TABLE A-9. Continued

```
                                                  POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR        P          SR

SECTOR    1 TOTAL
                       .37918+02  .12274+04

   BY FUEL --
  6 HIGH S RES. OIL    .56127+01  .18169+03
  7 MED  S RES. OIL    .14084+02  .45591+03
  8 LOW  S RES. OIL    .18221+02  .58982+03

   BY EFFLUENT STREAMS --
  1 FLUE GAS                      .19661+02
  3 BOTTM HOPPER ASH   .37918+02  .12078+04

      - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-9. Continued

```
                                                                POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR       P          SR

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  201 - WALL FIRED W-TUBE  >29.3
 15          .05  1                   .38382+01
 15          .05  3   .74023+01   .23578+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .38382+01
  3 BOTTM HOPPER ASH   .74023+01   .23578+03

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  202 - STOKER W-TUBE      >29.3
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  203 - SINGLE BURNER W-T  <29.3
 15               1                   .35852+01
 15               3   .69142+01   .22023+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .35852+01
  3 BOTTM HOPPER ASH   .69142+01   .22023+03

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  204 - SCOTCH FIRETUBE    <29.3
 15               1                   .56941+01
 15               3   .10981+02   .34978+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .56941+01
  3 BOTTM HOPPER ASH   .10981+02   .34978+03

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  205 - FIREBOX FIRETUBE   <29.3
 15               1                   .36695+01
 15               3   .70769+01   .22541+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .36695+01
  3 BOTTM HOPPER ASH   .70769+01   .22541+03

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  206 - STOKER FIRED W-TUBE <100
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  208 - CAST IRON BOILERS
 15               1                   .11750+01
 15               3   .22660+01   .72177+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                          .11750+01
  3 BOTTM HOPPER ASH   .22660+01   .72177+02

          SECTOR    2 - PACKAGED BOILERS                  EQUIPMENT TYPE  209 - STOKER F-T BOILER  <29.3
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
```

TABLE A-9. Continued

```
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR        P          SR

          SECTOR    2 - PACKAGED BOILERS
 15               1                .22294+01
 15               3   .42996+01   .13695+03
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                       .22294+01
  3 BOTTM HOPPER ASH  .42996+01   .13695+03

          SECTOR    2 - PACKAGED BOILERS
 15               1                .41576+00
 15               3   .80182+00   .25539+02
EQUIPMENT TYPE EFFLUENT STREAM TOTAL --
  1 FLUE GAS                       .41576+00
  3 BOTTM HOPPER ASH  .80182+00   .25539+02
```

```
   POLLUTANTS (MEGAGRAMS/YEAR)

EQUIPMENT TYPE  210 - HRT BOILERS   <29.3 MJ/S


EQUIPMENT TYPE  211 - RES/COMM STEAM + HOT WAT
```

TABLE A-9. Continued

```
FUEL -CNTRL FAC- EFF                                    POLLUTANTS (MEGAGRAMS/YEAR)
TYPE  1   2   3  STR       P          SR

SECTOR     2 TOTAL
                       .39742+02  .12865+04

   BY FUEL --
 15 RESIDUAL OIL       .39742+02  .12865+04

   BY EFFLUENT STREAMS --
  1 FLUE GAS                      .20607+02
  3 BOTTM HOPPER ASH   .39742+02  .12659+04
        - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - - -
```

TABLE A-9. Concluded

```
                                      POLLUTANTS (MEGAGRAMS/YEAR)
FUEL -CNTRL FAC- EFF
TYPE  1   2   3  STR       P          SR

GRAND TOTAL
                       .77660+02  .25139+04

   BY FUEL --
  6 HIGH S RES. OIL    .56127+01  .18169+03
  7 MED  S RES. OIL    .14084+02  .45591+03
  8 LOW  S RES. OIL    .18221+02  .58982+03
 15 RESIDUAL OIL       .39742+02  .12865+04

*FIN
```

REFERENCES FOR APPENDIX A

A-1. Surprenant, Norman, et al., "Preliminary Emissions Assessment of Conventional Stationary Combustion Systems, Volume II," EPA-600/2-76-046b, March 1976.

APPENDIX B

1973 NEDS FUEL USE AND EMISSIONS REPORTS FOR LOS ANGELES (024) AND CHICAGO (067)

The data presented here are from recent (1976) output of NEDS. They do, however, represent 1973 emission and fuel data as was verified by checking these data against the 1973 reports. The two sources agreed to within 1.5 percent. These data were used for the model input after verification and correction as described in Section 7.1.3.

TABLE B-1. NEDS ANNUAL FUEL SUMMARY FOR CHICAGO, AQCR 067

•••NEDS ANNUAL FUEL SUMMARY REPORT•••
USER FILE CREATE DATE: WEDNESDAY OCTOBER 13, 1976

AQCR: METROPOLITAN CHICAGO (ILL-IND)
DATE OF RUN: 10/21/76

	ANTH COAL TONS	BITH COAL TONS	RESID OIL 1000 GALS	DIST OIL 1000 GALS	NAT GAS 10E6 CUFT	WOOD/BARK TONS	GASOLINE 1000 GALS	DIESEL 1000 GALS
AREA SOURCES								
STATIONARY								
RESIDENTIAL	45810	559960		333600	345280	2000		
INDUSTRIAL		1040200	2640	242900	169220			
COMM-INSTL		52680	188520	283490	120290			
MOBILE								
LIGHT VEHICLE							2422202	
HEAVY VEHICLE							134255	195869
RAILROAD								226360
OFF-HIGHWAY							27836	22330
VESSELS			18720				11259	15610
AREA TOTAL	45810	1652840	209880	859990	634790	2000	2595552	460169
POINT SOURCES								
EXT COMB								
ELEC GEN		10768982	136019	3198	58632			
INDUSTRIAL		1831256	375571	12143	87000	2235		
COMM-INSTL	6	163586	4787	16869	1857			
INPROCESS		76080	127205		55272			
INTERNAL COMB								
ELEC GEN				19937	52			
INDUSTRIAL					455			
COMM-INSTL								
POINT TOTAL	6	12839904	643582	52147	203268	2235		
GRAND TOTAL	45816	14492744	853462	912137	838058	4235	2595552	460169

	LIGNITE TONS	COKE TONS	BAGASSE TONS	PROCESS GAS 10E6 CUFT	LIQ-PETRO 1000 GALS	JET FUEL 1000 GALS	SOLID WASTE TONS	LIQUID WASTE 1000 GALS
POINT SOURCES								
EXT COMB								
ELEC GEN				11715				
INDUSTRIAL				473924	3977			
COMM-INSTL								
INPROCESS		3180		125359	30000			
INTERNAL COMB								
ELEC GEN								
INDUSTRIAL								
COMM-INSTL								
GRAND TOTAL		3180		610998	33977			

Preceding page blank

TABLE B-2. NEDS ANNUAL EMISSIONS REPORT FOR CHICAGO, AQCR 067

```
                                          NATIONAL EMISSIONS DATA SYSTEM
                                          ******************************

                                          ENVIRONMENTAL PROTECTION AGENCY
                                          *******************************

          AQCR EMISSIONS REPORT                                               RUN DATE:      MONDAY   OCTOBER 18, 1976
          *********************                                        EMISSIONS AS OF:      OCTOBER 13, 1976
            AQCR 067 METROPOLITAN CHICAGO (ILL-IND)

                                 PARTICULATES          SOX              NOX              HC               CO
                                 **************  **************  **************  **************  **************
                                  TONS / YR        TONS / YR        TONS / YR        TONS / YR        TONS / YR

  FUEL COMBUSTION
  ***************

     EXTERNAL COMBUSTION

        RESIDENTIAL FUEL (AREA)

           ANTHRACITE COAL                229             506               69               57             2061
           BITUMINOUS COAL               5600           29876              840             5600            25190
           DISTILLATE OIL                1668            7208             2002              500              839
           NATURAL GAS                   1726             109            13811             1381             3953
           WOOD                            25               1               10               20               20
           TOTAL (RESIDENTIAL)           9248           37695            16731             7558            31966

        ELEC GENERATION (POINT)

           BITUMINOUS COAL              29563          983089           177685             1610             5332
           RESIDUAL OIL                   369            3830            15091              191              255
           DISTILLATE OIL                  13              69              168                3                5
           NATURAL GAS                    298            2920            29699               93              529
           PROCESS GAS                    217            2903             8515               16               67
           OTHER                          939            9806            17030               32              135
           TOTAL (ELEC GEN)             25889          996612           293137             1896             6318

        INDUSTRIAL FUEL

           BITUMINOUS COAL
              AREA SOURCES              55933           57300             7801              520             1090
              POINT SOURCES             22385           59623            17273              951             1222
           RESIDUAL OIL
              AREA SOURCES                 30             357               79                9                5
              POINT SOURCES              3152           36689            21535              590              712
           DISTILLATE OIL
              AREA SOURCES               1822            5298             7287              349              986
              POINT SOURCES               921            1939            11556               81              339
           NATURAL GAS
              AREA SOURCES                896              51            15230              259             1938
              POINT SOURCES               928            2285            19590              183              869
```

TABLE B-2. Continued

PROCESS GAS					
POINT SOURCES	4614	24086	49637	524	1284
WOOD					
POINT SOURCES	9	2	3	2	2
LIQUID PETROL GAS					
POINT SOURCES	7	220	298	1	7
OTHER					
POINT SOURCES	126	2590	786	25	21
TOTAL (INDUSTRIAL)					
AREA SOURCES	58131	62956	30397	1142	2970
POINT SOURCES	31642	126930	120628	1813	4952
COMM-INSTITUTIONAL FUEL					
BITUMINOUS COAL					
AREA SOURCES	1375	3303	242	53	190
POINT SOURCES	7250	7858	1221	83	180
RESIDUAL OIL					
AREA SOURCES	2168	13551	5656	283	377
POINT SOURCES	55	384	144	7	10
DISTILLATE OIL					
AREA SOURCES	2126	6125	8505	425	567
POINT SOURCES	117	441	470	6	31
NATURAL GAS					
AREA SOURCES	601	36	7217	481	1203
POINT SOURCES	9	1	128	7	18
TOTAL (COMM-INST)					
AREA SOURCES	6271	23015	21620	1242	2337
POINT SOURCES	7431	9234	1963	104	240
TOTAL (EXTERNAL COMB)					
AREA SOURCES	73649	123666	68749	9942	36873
POINT SOURCES	64962	632776	365728	3763	11010
INTERNAL COMBUSTION (POINT)					
ELECTRIC GENERATION					
DISTILLATE OIL	50	349	676	0	0
NATURAL GAS	0	0	11	0	0
TOTAL (ELEC GEN)	50	349	687	0	0
TOTAL (INTERNAL COMB)	50	349	687	0	0
TOTAL (FUEL COMBUSTION)					
AREA SOURCES	73649	123666	68749	9942	36873
POINT SOURCES	65013	633124	366415	3763	11010
INDUSTRIAL PROCESS (POINT)					
CHEMICAL MANUFACTURING	7172	11519	11908	2770	1359
FOOD/AGRICULTURAL	8145	94	0	0	0
PRIMARY METAL	53753	60354	13345	25146	4522318
SECONDARY METALS	6982	3504	29	163	30328
MINERAL PRODUCTS	157051	5776	661	162	275

TABLE B-2. Continued

PETROLEUM INDUSTRY	5495	55058	7692	10251	302120
WOOD PRODUCTS	8	1	8	1	1
EVAPORATION	108	0	1	174699	0
METAL FABRICATION	867	24	10	2	2
INPROCESS FUEL	1021	49148	5309	96	239
OTHER/NOT CLASSIFIED	918	8601	4934	3595	29913
TOTAL (INDUSTRIAL)	241219	194098	43391	216830	4886550
SOLID WASTE DISPOSAL					
********************					
GOVERNMENT (POINT)					
MUNICIPAL INCINERATION	10777	1258	1007	2191	16075
TOTAL (GOVERNMENT)	10777	1258	1007	2191	16075
RESIDENTIAL (AREA)					
ON SITE INCINERATION	4394	69	137	12358	37079
OPEN BURNING	5364	335	2011	10058	28496
TOTAL (RESIDENTIAL)	9758	404	2149	22415	65570
COMMERCIAL-INSTITUTIONAL					
ON SITE INCINERATION					
AREA SOURCES	1552	485	582	970	2230
POINT SOURCES	23	3	3	23	32
OPEN BURNING					
AREA SOURCES	583	36	219	1094	3098
POINT SOURCES	1096	0	123	296	3077
APARTMENT					
POINT SOURCES	13	0	1	7	9
TOTAL (COMM-INST)					
AREA SOURCES	2135	521	801	2063	5329
POINT SOURCES	1082	9	127	276	3117
INDUSTRIAL					
ON SITE INCINERATION					
AREA SOURCES	3193	998	1197	1996	9590
POINT SOURCES	3921	605	508	3572	5332
OPEN BURNING					
AREA SOURCES	3291	206	1234	6171	17485
TOTAL (INDUSTRIAL)					
AREA SOURCES	6984	1204	2432	8167	22075
POINT SOURCES	3921	605	508	3572	5332
TOTAL (SOLID WASTE DISP)					
AREA SOURCES	18377	2129	5381	32695	92973
POINT SOURCES	15280	1866	1641	5989	29525
TRANSPORTATION (AREA)					
********************					
LAND VEHICLES					

TABLE B-2. Concluded

GASOLINE					
LIGHT VEHICLES	20460	5304	177787	258923	1469120
HEAVY VEHICLES	1229	466	13457	33023	181794
OFF HIGHWAY	149	78	1698	4788	54280
TOTAL (GASOLINE)	21837	5848	192942	296734	1705194
DIESEL					
HEAVY VEHICLES	2253	3154	29143	3399	14499
OFF HIGHWAY	372	333	4120	451	1161
RAIL	2830	6451	41877	10639	14713
TOTAL (DEISEL)	5454	9938	75140	14489	30374
AIRCRAFT					
MILITARY	206	39	99	479	514
CIVIL	100	20	90	443	2530
COMMERCIAL	296	428	4147	5447	11239
TOTAL (AIRCRAFT)	602	487	4336	6369	14284
VESSELS					
DIESEL FUEL	187	234	1748	459	612
RESIDUAL OIL	181	2677	391	27	13
GASOLINE	0	35	154	5241	16663
TOTAL (VESSELS)	368	2947	2294	5727	17288
GAS HANDLING EVAP LOSS	0	0	0	37387	0
TOTAL (TRANSPORTATION)	28261	19219	274712	360707	1767140
MISCELLANEOUS (AREA) •••••••••••••••••••					
SOLVENT EVAPORATION LOSS	0	0	0	184118	0
TOTAL (MISCELLANEOUS)	0	0	0	184118	0
GRAND TOTAL •••••••••••					
AREA SOURCES	120288	145014	348842	587412	1896986
POINT SOURCES	321512	829088	411447	226582	4922085
TOTAL	441799	974102	760289	813994	6819072

TABLE B-3. NEDS ANNUAL FUEL SUMMARY FOR LOS ANGELES, AQCR 024

```
                                            ***NEDS ANNUAL FUEL SUMMARY REPORT***
                                                                  USER FILE CREATE DATE: WEDNESDAY   OCTOBER 13, 1976

   AQCR:  METROPOLITAN LOS ANGELES (CALIF)                        DATE OF RUN: 10/26/76

                      ANTH COAL    BITM COAL    RESID OIL    DIST OIL     NAT GAS      WOOD/BARK    GASOLINE     DIESEL
                     ************ ************ ************ ************ ************ ************ ************ ************
                        TONS         TONS       1000 GALS    1000 GALS    10E6 CUFT      TONS       1000 GALS    1000 GALS

   AREA SOURCES
     STATIONARY
       RESIDENTIAL                    1900                      4150       341710       19200
       INDUSTRIAL                                 183530      145060        42190
       COMM-INSTL                                 272910       99250       111370

     MOBILE
       LIGHT VEHICLE                                                                               4274588
       HEAVY VEHICLE                                                                                253156       212924
       RAILROAD                                                                                                  190410
       OFF-HIGHWAY                                                                                  108589        57860
       VESSELS                                     22530                                              3871        33570

       AREA TOTAL                     1900        478970      249260       495270       19200      4640204       494764

   POINT SOURCES
     EXT COMB
       ELEC GEN                                  1317212       22530       267153
       INDUSTRIAL                    70000         28739       14921        17319
       COMM-INSTL                                     16        1281         3186

     INPROCESS                                     13514        6752        17117

     INTERNL COMB
       ELEC GEN                                                  220         2028
       INDUSTRIAL                                                            8396                                    24
       COMM-INSTL                                                                                                    90

       POINT TOTAL                   70000       1359481       45704       315999                                   114

      GRAND TOTAL                    71900       1838451      294964       811269       19200      4640204       494878

                      LIGNITE      COKE         BAGASSE      PROCESS GAS  LIQ-PETRO    JET FUEL     SOLID WASTE  LIQUID WASTE
                     ************ ************ ************ ************ ************ ************ ************ ************
                        TONS         TONS         TONS       10E6 CUFT    1000 GALS    1000 GALS      TONS       1000 GALS

   POINT SOURCES
     EXT COMB
       ELEC GEN
       INDUSTRIAL                                              38202
       COMM-INSTL

     INPROCESS                                                                65

     INTERNL COMB
       ELEC GEN
       INDUSTRIAL
       COMM-INSTL

      GRAND TOTAL                                              38202          65
```

TABLE B-4. NEDS ANNUAL EMISSIONS REPORT FOR LOS ANGELES, AQCR 024

NATIONAL EMISSIONS DATA SYSTEM

ENVIRONMENTAL PROTECTION AGENCY

AQCR EMISSIONS REPORT
AQCR 024 METROPOLITAN LOS ANGELES (CALIF)

RUN DATE: SATURDAY OCTOBER 18, 1976
EMISSIONS AS OF: OCTOBER 13, 1976

	PARTICULATES TONS / YR	SOX TONS / YR	NOX TONS / YR	HC TONS / YR	CO TONS / YR
FUEL COMBUSTION					
EXTERNAL COMBUSTION					
RESIDENTIAL FUEL (AREA)					
BITUMINOUS COAL	19	32	3	19	85
DISTILLATE OIL	21	60	25	6	10
NATURAL GAS	1709	103	13668	1367	3417
WOOD	240	14	96	192	192
TOTAL (RESIDENTIAL)	1988	209	13792	1584	3705
ELEC GENERATION (POINT)					
RESIDUAL OIL	4953	40978	54121	2144	1549
DISTILLATE OIL	18	779	370	272	1
NATURAL GAS	1194	88	67446	295	1741
OTHER	4682	44472	29029	1728	1
TOTAL (ELEC GEN)	10848	86317	150966	4440	3292
INDUSTRIAL FUEL					
BITUMINOUS COAL					
POINT SOURCES	3413	798	1050	11	35
RESIDUAL OIL					
AREA SOURCES	2112	26284	5509	275	347
POINT SOURCES	78	638	432	23	2
DISTILLATE OIL					
AREA SOURCES	1094	2101	4376	219	292
POINT SOURCES	101	583	408	104	8
NATURAL GAS					
AREA SOURCES	211	13	3797	63	359
POINT SOURCES	61	4	2377	85	55
PROCESS GAS					
POINT SOURCES	140	4022	2116	385	22
COKE					
POINT SOURCES	35	0	22	6	5

TABLE B-4. Continued

OTHER					
POINT SOURCES	96	633	590	51	10
TOTAL (INDUSTRIAL)					
AREA SOURCES	3917	28398	13682	558	1018
POINT SOURCES	3925	6678	6995	665	137
COMM-INSTITUTIONAL FUEL					
RESIDUAL OIL					
AREA SOURCES	3138	39063	8187	409	546
POINT SOURCES	0	1	0	0	0
DISTILLATE OIL					
AREA SOURCES	744	1430	2977	149	198
POINT SOURCES	6	31	38	1	2
NATURAL GAS					
AREA SOURCES	557	33	6682	445	1114
POINT SOURCES	14	1	164	11	27
OTHER					
POINT SOURCES	99	175	4039	129	21
TOTAL (COMM-INST)					
AREA SOURCES	4440	40526	17847	1004	1858
POINT SOURCES	119	207	4242	141	49
TOTAL (EXTERNAL COMB)					
AREA SOURCES	9845	69133	45321	3195	6581
POINT SOURCES	14891	93203	162203	5296	3479
INTERNAL COMBUSTION (POINT)					
ELECTRIC GENERATION					
DISTILLATE OIL	193	87	3687	97	2
NATURAL GAS	19	2	1499	50	6
TOTAL (ELEC GEN)	211	89	5186	147	7
INDUSTRIAL FUEL					
DISTILLATE OIL	3	1	32	1	0
NATURAL GAS	0	4	1650	2200	0
DIESEL FUEL	0	1	6	0	1
OTHER	0	0	0	29	0
TOTAL (INDUSTRIAL)	3	6	1687	2230	1
COMM-INSTITUTIONAL					
DIESEL	2	3	21	2	5
TOTAL (COMM-INST)	2	3	21	2	5
ENGINE-TESTING					
AIRCRAFT	9	8	81	8	308
TOTAL (ENG TESTNG)	9	8	81	8	308
TOTAL (INTERNAL COMB)	225	107	6975	2386	321
TOTAL (FUEL COMBUSTION)					

TABLE B-4. Continued

AREA SOURCES	9845	69133	45321	3195	6581
POINT SOURCES	15116	93309	169178	7632	3800
INDUSTRIAL PROCESS (POINT)					
CHEMICAL MANUFACTURING	1517	30610	2093	2927	177
FOOD/AGRICULTURAL	832	0	24	77	3
PRIMARY METAL	1160	6413	4092	106	1765
SECONDARY METALS	1592	1409	442	104	1652
MINERAL PRODUCTS	30481	5047	14314	336	463
PETROLEUM INDUSTRY	1562	25421	13520	18753	427
WOOD PRODUCTS	2775	90	0	4	1080
EVAPORATION	8489	0	45	169330	239
METAL FABRICATION	189	0	0	0	0
TEXTILE MANUFACTURING	37	0	6	34	1
INPROCESS FUEL	325	511	3501	2897	40
OTHER/NOT CLASSIFIED	5	0	0	18	0
TOTAL (INDUSTRIAL)	48963	69502	38036	194585	5847
SOLID WASTE DISPOSAL					
GOVERNMENT (POINT)					
OPEN BURNING	9	1	3	21	48
TOTAL (GOVERNMENT)	9	1	3	21	48
RESIDENTIAL (AREA)					
ON SITE INCINERATION	14571	228	455	40982	122946
OPEN BURNING	7942	496	2978	14891	42190
TOTAL (RESIDENTIAL)	22513	724	3433	55872	165136
COMMERCIAL-INSTITUTIONAL					
ON SITE INCINERATION					
AREA SOURCES	205	64	77	128	294
OPEN BURNING					
AREA SOURCES	687	43	258	1289	3651
OTHER					
POINT SOURCES	1	0	2	0	0
TOTAL (COMM-INST)					
AREA SOURCES	892	107	334	1417	3945
POINT SOURCES	1	0	2	0	0
INDUSTRIAL					
ON SITE INCINERATION					
AREA SOURCES	242	76	91	152	348
POINT SOURCES	30	24	17	32	66
OPEN BURNING					
AREA SOURCES	682	43	256	1280	3625
OTHER					
POINT SOURCES	8	12	7	2	3
TOTAL (INDUSTRIAL)					
AREA SOURCES	925	118	347	1431	3974

TABLE B-4. Concluded

POINT SOURCES	38	41	24	34	64
TOTAL (SOLID WASTE DISP)					
AREA SOURCES	24330	999	4115	58720	173054
POINT SOURCES	48	42	29	55	117
TRANSPORTATION (AREA)					
LAND VEHICLES					
GASOLINE					
LIGHT VEHICLES	34058	8830	277048	487430	3145300
HEAVY VEHICLES	2172	823	22283	66444	388953
OFF HIGHWAY	581	304	6624	18677	211749
TOTAL (GASOLINE)	36811	9957	305955	572551	3746001
DIESEL					
HEAVY VEHICLES	2296	3214	27826	4059	20453
OFF HIGHWAY	963	862	10675	1169	3009
RAIL	2380	5427	35226	8949	12377
TOTAL (DEISEL)	5639	9503	73727	14177	35838
AIRCRAFT					
MILITARY	3133	548	1505	7290	7825
CIVIL	480	95	433	2124	12139
COMMERCIAL	237	393	3324	4366	9008
TOTAL (AIRCRAFT)	3850	1036	5262	13780	28973
VESSELS					
DIESEL FUEL	403	504	3760	987	1316
RESIDUAL OIL	221	3279	479	33	16
GASOLINE	0	12	53	1802	5729
TOTAL (VESSELS)	624	3795	4292	2822	7061
GAS HANDLING EVAP LOSS	0	0	0	58624	0
TOTAL (TRANSPORTATION)	46924	24291	389237	661955	3817874
MISCELLANEOUS (AREA)					
SOLVENT EVAPORATION LOSS	0	0	0	139127	0
TOTAL (MISCELLANEOUS)	0	0	0	139127	0
OTHER (POINT)	29	0	82	301	4
GRAND TOTAL					
AREA SOURCES	81099	94373	438672	862947	3997509
POINT SOURCES	64157	162853	207326	202573	9768
TOTAL	145256	257226	645999	1065520	4007276

APPENDIX C

MOBILE SOURCE EMISSIONS

This appendix presents a simplified methodology for the estimation of NO_x emissions from all mobile sources. Mobile sources include both highway and off-highway sources. Because of the large differences in normal operation a different methodology was used for each category. The method of calculation for each category, the base year emissions, and two future projections for the Los Angeles and Chicago Air Quality Control Regions (AQCRs) are described.

Highway Vehicles

The approach used for the estimation of highway motor vehicle emissions considered the following variables: motor vehicle population distribution by model year, average annual distance traveled by model year, deterioration factors, vehicle types, emissions factors, and speed adjustment factors. These variables were combined in the following manner where Q is the total NO_x emissions in Gg/yr from all highway motor vehicles.

$$Q = \Sigma Q_l \qquad \text{(C-1)}$$

where $Q_l = \Sigma_k \ FTP_{lk} \ KM_{lk} \ EF_{lk} \ DF_{lk} \ RSF_{lk} \ POP_l$

FTP = motor vehicle population distribution

KM = average annual distance traveled (km)

EF = emission factor in g/km

DF = deterioration factor

RSF = speed adjustment factor

POP = total motor vehicle population

l = vehicle type

k = vehicle age

The normal disaggregation of motor vehicles by vehicle type was used. The four different categories are light-duty passenger vehicles (LDV), light-duty trucks (LDT, GVW* <2,725 kg) (6,000 lbs), heavy-duty gasoline-powered trucks (HDG, GVW >2,725 kg), and heavy-duty diesel-powered trucks (HDD, GVW >2,725 kg).

The motor vehicle population distributions by vehicle age are given in Table C-1 for all vehicle types. The distributions are assumed to represent future ownership patterns and vehicle attrition rates.

The values of annual average distance traveled are also given in Table C-1. Numerous estimates of these values are presented in the literature (References C-1 through C-4). The figures for all LDV and LDT agreed reasonably well as noted at the bottom of the table. One probable cause for the large discrepancy among the heavy-duty vehicles is that some sources consider the total distance traveled by these vehicles. However, in estimating the emissions for a particular AQCR, consider only the distance traveled within the particular AQCR in question. Since a large portion of the annual travel of heavy-duty vehicles (especially the HDD) occurs on long intercity freight hauls, the seemingly low travel statistics as given by Reynolds (Reference C-3) were used. (These values are estimates of the distance traveled within one particular AQCR.)

Deterioration factors represent the decreasing efficiency of pollution control devices. Different deterioration factors for different types and degrees of emission control have been proposed (References C-1, C-5, C-6, and C-7). These deterioration factors will depend on several variables and particularly the frequency of routine maintenance procedures. Since these factors are speculative and add to the complexity of the calculation, one deterioration factor was assumed to be adequate for all levels of NO_x control. The deterioration factors as given by the Senate Investigation Committee on "Air Quality and Automobile Emission Control" (Reference C-8) are shown in Table C-2. No deterioration factor was used for the heavy-duty vehicles because it was assumed that these trucks would receive routine maintenance throughout the vehicle life.

The quantification of emissions from nonconstant speed operation requires the identification of a time-speed plot representative of the area of interest. The variation of emission rates with average and constant vehicle speed as developed by Nordsieck (Reference C-9) is illustrated in Figure C-1. Due to the lack of any information on average route speeds in Los Angeles or Chicago and since the driving cycles used by the Environmental Protection Agency are assumed to be representative of "typical" driving patterns, the route speed adjustment factor was assumed to be unity.

---

*GVW: gross vehicle weight

TABLE C-1. VEHICLE POPULATION AND ANNUAL DISTANCE TRAVELED VS. VEHICLE AGE

Vehicle Age	LDV		LDT		HDG		HDD	
	FTP[a]	KM[b]	FTP[a]	KM[b]	FTP[a]	KM[b]	FTP[a]	KM[b]
1	0.081	23,040	0.061	23,040	0.037	31,300	0.077	45,000
2	0.110	22,560	0.097	22,560	0.078	31,300	0.135	45,000
3	0.107	20,640	0.097	20,640	0.078	28,800	0.134	41,200
4	0.106	18,240	0.097	18,240	0.078	28,800	0.131	41,200
5	0.102	13,760	0.083	13,760	0.075	22,400	0.099	32,200
6	0.096	10,900	0.076	10,900	0.075	22,400	0.090	32,200
7	0.088	9,100	0.076	9,100	0.075	17,600	0.082	25,400
8	0.077	7,700	0.063	7,700	0.068	17,600	0.062	25,400
9	0.064	6,400	0.054	6,400	0.059	13,400	0.045	19,400
10	0.049	5,800	0.043	5,800	0.053	13,400	0.033	19,400
11	0.033	5,600	0.036	5,600	0.044	6,900	0.025	9,800
12	0.023	5,600	0.024	5,600	0.032	6,900	0.015	9,800
≥ 13	0.064	5,600	0.185	5,600	0.247	6,900	0.064	9,800

[a] Fraction of total population of vehicle, Reference C-4

[b] Distance traveled in km, Reference C-3

NOTE: AP-42 (Reference C-4) annual mileage figures gave a severe underestimate of the HDG, and HDD vehicle population when that figure was checked with the 1973 NEDS data. The annual mileage for LDV and LDT agreed reasonably well between References C-3 and C-4. Reference C-3 data were used throughout for consistency. The vehicle population distributions were similar for these two sources.

TABLE C-2. DETERIORATION FACTORS FOR LIGHT-DUTY PASSENGER CARS AND LIGHT-DUTY TRUCKS[a]

Vehicle Age	Deterioration Factor
1	0.90
2	0.95
3	0.98
4	1.00
5	1.01
6	1.02
7	1.03
8	1.04
9	1.04
10	1.05
11	1.06
12	1.06
≥13	1.07

[a] Reference C-8

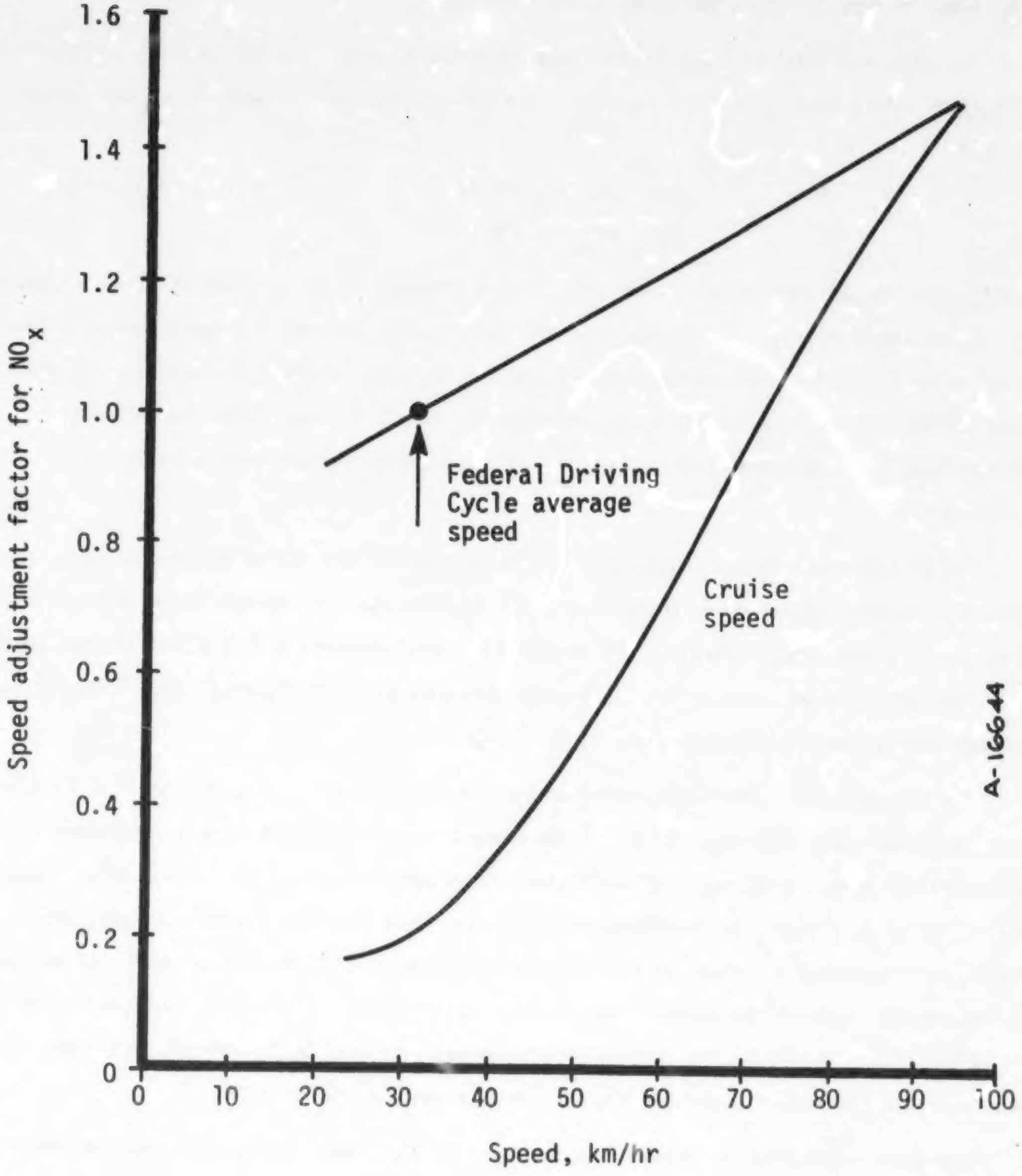


Figure C-1. Speed variation of speed adjustment factors for oxides of nitrogen (Reference C-9).

The emission factors depend upon the emission standards instituted by law. This factor, therefore, will be different for each model year and vehicle type. The emissions factors for LDV and LDT are legislated in terms of grams per mile; and the emission factors for heavy-duty vehicles are mandated in terms of grams per brake-horsepower-hour.

For this report all of these factors were converted to g/km. For LDV and LDT this is a simple matter of changing miles to kilometers. For HDG and HDD the following conversion factors were used:

$$\text{HDG:}\quad EF_{SI} = 0.777\ EF_L$$

$$\text{HDD:}\quad EF_{SI} = 1.522\ EF_L$$

where EF_{SI} is the emission factor in g/km, EF_L is the emission factor in grams per brake-horsepower-hour and the conversion factor includes consideration of units, thermal and mechanical efficiency, heating value of the fuel and average fuel consumption (Reference C-10). In addition, the emission factor for HDG and HDD include both hydrocarbon and NO_x together. Therefore, the values of EF_L, from Reference C-11, have been reduced by 1.0 gram per brake-horsepower-hour to reflect only NO_x emissions.

The highway motor vehicle population in the Los Angeles AQCR was calculated by taking the county-wide vehicle population as reported by the U.S. Department of Transportation (Reference C-12) and multiplying that vehicle population by an activity level (Reference C-2) within the Los Angeles AQCR. This was necessary because the Los Angeles AQCR does not follow county lines. The resultant truck and automobile population is given in Table C-3.

The highway motor vehicle population of the Chicago AQCR was calculated from U.S. Department of Transportation data (Reference C-12). Since these data were only available for Standard Metropolitan Statistical Areas (SMSA) they did not include three counties within the Chicago AQCR. However, according to an interagency study (Reference C-13), the three counties (Kendall, Grundy, and Kankakee) contributed 2.6 percent of all vehicular emissions within the Chicago AQCR. It was assumed that the vehicle distribution within these counties was similar to the vehicle distribution in the rest of the AQCR. Therefore, the vehicle population was increased by 2.6 percent to account for these counties. Table C-4 summarizes the Chicago AQCR vehicle population.

The truck population was broken down further into light-duty, heavy-duty gasoline-powered, and heavy-duty diesel-powered trucks. Table C-5 summarizes the vehicle distribution breakdown of all registered trucks and automobiles. The data for the Los Angeles AQCR breakdown were based on actual Los Angeles data from References C-2 and C-3. Similar data were not available for the Chicago

TABLE C-3. LOS ANGELES AQCR REGISTERED VEHICLE POPULATION[a]

County	Autos	Trucks	Total	Activity
Los Angeles	3,764,625	605,260	4,369,885	0.96
Riverside	251,343	63,470	314,813	0.70
San Bernardino	342,715	150,515	493,230	0.80
Santa Barbara	143,076	29,435	172,511	0.59
Ventura	209,123	43,120	252,243	1.00
Orange	889,091	145,721	1,034,812	1.00
Total	5,247,792	951,087	6,198,879	

[a] Reference C-12

TABLE C-4. CHICAGO AQCR REGISTERED VEHICLE POPULATION[a]

County	Autos	Trucks	Total
McHenry	63,225	11,002	74,227
Lake	187,559	22,649	210,208
Kane	134,717	20,255	154,972
DuPage	280,806	27,328	308,134
Cook	2,264,779	173,624	2,438,403
Will	130,762	20,447	151,209
Lake, Ind.	234,289	34,210	268,499
Porter, Ind.	41,754	9,815	51,569

Kankakee	1.3%	of total NO_x production[b]
Grundy	.9%	
Kendall	.4%	

Therefore, increase vehicle population by 2.6%, giving totals:

Autos — 3,424,676
Trucks — 327,632
Total — 3,752,308

---

[a] Reference C-12
[b] Reference C-13

AQCR; therefore, it was assumed that the Chicago vehicle distribution was similar to the vehicle distribution within the New York AQCR (Reference C-14).

Off-Highway Mobile Sources

The off-highway mobile sources include the emissions from aircraft, railroads, ships, and all other off-highway vehicles. The emissions from these sources have traditionally been either assumed constant with time or neglected entirely (References C-15 and C-16). However, as motor vehicle emissions are reduced substantially in the future these other sources will contribute a much greater percentage of the total NO_x emissions. In fact, according to one of the most comprehensive emission surveys available (Reference C-17), railroads alone contributed 16 percent of the transportation area NO_x emissions and 8.5 percent of the total NO_x emissions in the Chicago AQCR. Therefore, the emissions from this category will be neither neglected nor assumed to remain constant in this study.

The emissions from these sources will be projected by multiplying the base year emissions by a compounded annual growth rate. If controls are expected to be implemented, as in the case of aircraft, a uniform reduction in emissions will be made at the time the regulation is expected to take full effect. This approach is used because of the general lack of available data on purchase rates, attrition rates, replacement rates, and degree of retrofit of new controls.

Base Year Calculation

It was possible to verify this methodology as a reasonable model of highway mobile source emissions. The daily total vehicle distance traveled in the Los Angeles AQCR was calculated from the annual distance traveled by vehicle type and model year as given in Tables C-1, C-3, C-4, and C-5. The resultant calculation yielded approximately 233 million vehicle km traveled in the Los Angeles AQCR in 1973. This agreed within 8 percent of the 253 million vehicle km traveled as reported in References C-2 and C-14.

Another check was made on the emissions methodology. Table C-6 contains the emission factors used prior to and including 1973 for all highway vehicle classes. Values between 2.17 and 3.72 g/km (3.5 and 6 g/mi) are commonly reported as LDV and LDT emission factors (References C-3, C-6, C-8, C-18, C-19). Unregulated NO_x emissions were affected by emission regulations on hydrocarbons and carbon monoxide. This undoubtedly accounted for some of the variation in the reported NO_x emission factors. The emission factor reported by the EPA for 1971 light-duty motor vehicles was 2.92 g/km and was also approximately equal to the mean of the reported NO_x emission factors for LDV and LDT. Therefore, 2.92 g/km was chosen as the emission factor for all vehicles prior to NO_x

TABLE C-5. VEHICLE DISTRIBUTION AS A PERCENTAGE OF ALL REGISTERED TRUCKS AND AUTOMOBILES

	Los Angeles AQCR[a]	Chicago AQCR[b]
LDV	87.7	92.1
LDT	10.0	4.0
HDG	1.7	3.25
HDD	0.6	0.65

[a] Based on data for the Los Angeles AQCR (References C-2, C-3).

[b] Based on data for the New York City AQCR (Reference C-14).

TABLE C-6. MOBILE SOURCE EMISSION FACTORS g/km[a]

	LDV		LDT			
	Calif.	Fed.	Calif.	Fed.	HDG	HDD
<1972	2.92	2.92	2.92	2.92	11.7	27.3
1972	1.92	2.92	1.92	2.92	11.7	27.3
1973	1.92	1.92	1.92	1.92	11.7	27.3

[a] Reference C-4

TABLE C-7. A COMPARISON OF THE CALCULATED VEHICLE POPULATION AND THE REGISTERED VEHICLE POPULATION (1,000 VEHICLES)

	Los Angeles AQCR			Chicago AQCR		
	Calc.	Registered	% Diff	Calc.	Registered	% Diff
LDV & LDT	6,335	6.056	4.6	4,013	3,606 (3,868)[a]	11.2 (3.7)
HDG	98	105	6.7	59	122 (130)	51.6 (54.6)
HDD	28	37	24.3	29	24 (26)	20.8 (10.3)

[a] The data in parentheses represent Chicago Area Transportation Study (CATS) registered vehicle population (Reference C-20). The remaining data represent the U.S. Department of Transportation vehicle population (Reference C-12).

emission regulations. This was prior to 1972 for California vehicles and prior to 1973 for the other states.

The NO_x emission factor of 11.7 g/km for heavy-duty gasoline-powered vehicles was taken from Reference C-9. There is a wide range of emission factors reported in the literature for heavy-duty diesel vehicles. The value of 27.3 g/km is taken from Reference C-3.

The vehicle population was calculated using the vehicle age and use distribution in Table C-1, pre-1974 emission factors in Table C-6, and the total NO_x production for each vehicle type as reported in NEDS (Reference C-15). The calculated population was then compared to the registered vehicle population in Tables C-3 and C-4. This data was broken down by vehicle class as in Table C-5. Table C-7 summarizes the results of the calculations.*

Significant error exists in both heavy-duty vehicle categories. No adjustment in the emission factors used could account for the error. The HDG in the Los Angeles AQCR was in fair agreement; whereas, HDG in the Chicago AQCR was in poor agreement. Therefore, any adjustment in the emission factor would compromise the results in one region to benefit another region. In addition, the calculated HDD population was below the registered population in the Los Angeles AQCR and above the registered population in the Chicago AQCR. Therefore, any adjustment of the emission factor here would again compromise the results in one region to the benefit of another. It was shown, however, that the calculated LDV and LDT population were in fair agreement with the registered population. Since LDV and LDT are the largest categories of mobile source pollution, this agreement was considered of most importance. Therefore, no adjustment to the emissions methodology was made. Furthermore, the calculated vehicle population was used as the base year vehicle population to force agreement between this model and NEDS.

Growth Projections

The National Emissions Data System, NEDS (Reference C-17), was selected as the most comprehensive data base available for the emissions in both the Los Angeles and the Chicago AQCR. 1973 was selected as the base year for all emission projections. Two scenarios were then selected to establish an upper and lower bound to the probable emissions from mobile sources for future years.

The first scenario is the nominal growth case. In this scenario, the LDV and LDT populations continue to grow at the historic rate of 3.5 percent per year (Reference C-8) until the end of the century. This nominal growth scenario was combined with limited emission controls of 0.62 g/km by 1981. The emission factors used in the Chicago AQCR are essentially the Federal standards and those used in the Los Angeles AQCR are the California standards.*

---

*The vehicle population in the Chicago AQCR was also supplied by the Chicago Area Transportation Study (CATS) (Reference C-20).

The low growth scenario assumed that the LDT and LDV population would parallel the projected human population growth of 1 percent per year until the end of the century (References C-15, C-19). The emission factors for this scenario assume a staged reduction in emission standards until the statutory standard of 0.25 g/km is achieved in 1985 for the nation (1981 for California).

The heavy-duty vehicle emission standards and growth rates are the same for both the nominal and the low growth scenario. The growth in this vehicle class was assumed to parallel the population growth through the end of the century. Historically, this vehicle class has grown at approximately the human population growth rate (i.e., 2 percent per year for the heavy-duty vehicles compared to 1.2 percent per year for the national human population (References C-11, C-21). The emission factors for heavy-duty vehicles have been set for both California and the nation (Reference C-11).

The emission factors for all off-highway mobile sources are held constant at the 1973 level. Presently there is no control strategy for railroads, ships, and other off-highway vehicles. Aircraft is the only off-highway mobile source that currently has a control strategy.† The strategy is in its early development, however. The California Air Resources Board predicts that aircraft emission factors (mass of NO_x per landing and takeoff cycle) will be reduced by 30 percent in 1985 (References C-1, C-22, C-23). Because of the general lack of available data on purchase rates, attrition rates, replacement rates, and degree of retrofit of new controls, a uniform reduction of 30 percent in aircraft emissions is assumed in 1985 for both scenarios. Since aircraft are interstate vehicles, any emission standards will probably be enforced on the national level and hence, apply to all aircraft serving the U.S. Furthermore, in the low growth scenario, aircraft emissions were assumed to be reduced by 50 percent by 1995 (References C-22, C-23). The nominal growth scenario has no regulations beyond the 1985 level for aircraft.

---

*It should be noted that California has legislated emission standards for all highway vehicles until 1980 (Reference C-4). In the immediate future the 1981 standard will be written. It is presently uncertain whether the standard will be held at the 0.62 g/km standard or reduced to the statutory standard of 0.25 g/km. The Federal Government, on the other hand, has no standards beyond 1977 except the statutory standard of 0.25 g/km. It was considered highly unlikely that this would remain unchanged. Therefore, it was assumed that in 1977 the Congress will establish a staged reduction of emission standards similar to that of California's, so that after 1978 there will no longer be a two-car standard for the nation's automobile industry.

†The rationale for addressing aircraft emissions in lieu of other sources that emit more in a particular AQCR (i.e., railroads) is that the aircraft emissions are highly localized. The aircraft emissions are largely released in the immediate vicinity of the airport and contribute significantly to the air quality of the region surrounding the airport. Therefore, regulation of their emissions is required.

The growth rate of all off-highway mobile sources was assumed to parallel the projected national population growth rate of 1 percent per year. Several authoritative reports have suggested such a growth pattern (References C-1, C-22, C-23, C-24).

All the growth and emission rates for mobile sources are summarized in Table C-8. The results of the calculations for the total mobile source NO_x emissions in Gg per year are presented in Table C-9 for the Los Angeles AQCR and in Table C-10 for the Chicago AQCR.

TABLE C-8. MOBILE SOURCE EMISSION FACTORS (g/km) AND ANNUAL GROWTH RATES

	Nominal					Low					Both Cases/Both AQCR's		
	LDV		LDT		Aircraft[b]	LDV		LDT		Aircraft[b]			
	Calif[a]	Fed	Calif	Fed		Calif	Fed	Calif	Fed		HDG	HDD	Rail, ships, etc.
<1972	2.9	2.9	2.9	2.9	No regulation	2.9	2.9	2.9	2.9	No regulation	11.7	27.4	No regulation
1972	1.9	2.9	1.9	2.9		1.9	2.9	1.9	2.9		11.7	27.4	
1973	1.9	1.9	1.9	1.9		1.9	1.9	1.9	1.9		11.7	22.8	
1974	1.2	1.9	1.2	1.9		1.2	1.9	1.2	1.9		11.7	22.8	
1975	1.2	1.9	1.2	1.9		1.2	1.9	1.2	1.9		7.0	13.7	
1977	0.93	1.2	1.2	1.2		0.93	1.2	0.93	1.2		5	9.8	
1978	0.93	0.93	1.2	1.2		0.93	0.93	0.93	0.93		↓	↓	
1980	0.62	0.62	0.93	0.93		0.62	0.62	0.62	0.62				
1981	↓	↓	0.62	0.62	.30 Reduction	0.25	0.62	0.25	0.62				
1985			↓	↓		↓	0.25	↓	0.25	.30 Reduction			
1990					↓		↓		↓	.40 Reduction			
1995										.50 Reduction			
2000										↓			
Annual Growth Rate	3.5%				1%	1%				1%	1%	1%	1%

[a] Reference C-11

[b] Reference C-23

TABLE C-9. MOBILE SOURCE EMISSIONS OF OXIDES OF NITROGEN IN THE LOS ANGELES AQCR (Gg/YEAR)

	1973	1975		1980		1985		1990		1995		2000	
		A	B	A	B	A	B	A	B	A	B	A	B
LDV	224	172	164	115	96.6	84.5	40.2	87.0	25.4	101	23.7	121	24.9
LDT	27.7	19.7	18.8	16.2	13.6	12.9	5.56	10.7	3.32	11.4	2.68	13.62	2.81
HDG	20.2	20.6	20.6	17.2	17.2	12.25	12.25	8.99	8.99	8.40	8.40	8.82	8.82
HDD	25.3	21.5	21.5	16.3	16.3	9.65	9.65	8.51	8.51	8.73	8.73	9.18	9.18
Aircraft	4.8	4.87	4.87	5.12	5.12	3.77	3.77	3.96	2.94	4.15	3.00	4.38	3.08
Other	51.6	54.2	54.2	57.0	57.0	59.8	59.8	62.9	62.9	66.1	66.1	69.5	69.5
Total	353.6	292.87	283.97	226.82	205.82	182.87	131.23	182.06	112.08	199.78	112.6	226.5	118.29

TABLE C-10. MOBILE SOURCE EMISSIONS OF OXIDES OF NITROGEN IN THE CHICAGO AQCR (Gg/YEAR)

	1973		1975		1980		1985		1990		1995		2000	
	A	B	A	B	A	B	A	B	A	B	A	B	A	B
LDV	155	155	134	128	92.6	80.0	61.0	44.6	59.6	21.1	68.5	17.1	81.4	17.0
LDT	6.72	6.72	5.22	4.97	4.34	3.65	3.90	1.83	3.09	0.90	3.30	0.71	3.92	0.65
HDG	12.2	12.2	12.5	12.5	10.2	10.2	7.26	7.26	5.32	5.32	4.97	4.97	5.22	5.22
HDD	26.5	26.5	25.7	25.7	17.1	17.1	10.0	10.0	8.91	8.91	9.15	9.15	9.61	9.61
Aircraft	35.9	35.9	36.6	36.6	38.5	38.5	28.3	28.3	29.7	25.45	31.3	22.41	32.8	23.5
Other	13.4	13.4	13.7	13.7	14.4	14.4	15.1	15.1	15.9	15.9	16.7	16.7	17.6	17.6
Total	249.7	249.7	227.7	221.5	177.1	163.8	125.6	107.1	122.5	77.58	133.9	125.0	150.55	73.58

REFERENCES FOR APPENDIX C

C-1. "Emissions Forecasting Methodologies," California Air Resources Board, CARB, July 1974, pp. 238-259.

C-2. "Preliminary Emissions Inventory and Air Quality Forecast 1974-1975," Final Report of the Boundaries and Forecasting Committee to the Air Quality Maintenance Planning Policy Task Force, Southern California Air Pollution Control District, May 10, 1976.

C-3. Reynolds, S. D. and J. H. Seinfeld, "Interim Evaluation of Strategies for Meeting Ambient Air Quality Standard for Photochemical Oxidant Appendix Projected Emissions for Los Angeles 1977," Environmental Science and Technology, Vol. 9, No. 5, May 1975, pp. 433-447.

C-4. "Compilation of Air Pollutant Emission Factors (Second Edition)," U.S. EPA AP-42, Supplement #5, December 1975.

C-5. "Handbook of Air Pollution Emissions from Transportation Systems."

C-6. Heywood, J. B. and M. K. Martin, "Aggregate Emissions from the Automobile Population," SAE 740536.

C-7. Tingle, D. S. and J. H. Johnson, "Emissions and Fuel Usage by the U.S. Truck and Bus Population and Strategies for Achieving Reductions," SAE 740537.

C-8. "Air Quality and Automobile Emission Control, Volume 4," prepared for the Committee on Public Works, United States Senate Serial No. 93-24.

C-9. Nordsieck, R. A., "Air Pollutant Emission Factor Estimates for California Motor Vehicles: 1967-2000," General Research Corporation, RM-1849, January 1975.

C-10. "Motor Vehicles Facts and Figures 1976," Motor Vehicles Manufacturers Association.

C-11. "California Air Resources Board Bulletin," Volume 7, No. 11, November-December 1976.

C-12. "Highway Statistics 1973," U.S. Department of Transportation, Federal Highway Administration.

C-13. Personal Communication with B.R. Eppright, Radian Corp., September 1976.

C-14. "Medium Duty Vehicle Emission Control Cost Effectiveness Comparisons, Volume 1 — Executive Summary," prepared by the Environmental Programs Group of the Aerospace Corporation under EPA Contract No. 68-01-0417, January 1974.

C-15. Trijonis, J. C., et al., "Emissions and Air Quality Trends in the South Coast Air Basin," California Institute of Technology, EQL Memorandum No. 16, January 1976.

C-16. "Air Quality, Noise, and Health," Office of the Secretary of Transportation, TAD-443.1, March 1976.

C-17. "1973 National Emissions Report," EPA Office of Air and Waste Management, Office of Air Quality Planning and Standards, EPA 450/2-76-007, May 1976.

C-18. Scheel, J. W., "A Method for Estimating and Graphically Comparing the Amounts of Air Pollution Emissions Attributable to Automobiles, Buses, Commuter Trains, and Rail Transit," SAE 720166.

C-19. "Meeting California's Energy Requirements 1975-2000," Stanford Research Institute, SRI Project ECC-2355.

C-20. Private communication with Emil Biedvon of Chicago Area Transportation Study, CATS, December 1976.

C-21. "World Almanac and Book of Facts 1977," Newspaper Enterprise Association, Inc., New York, New York.

C-22. "The State of California Implementation Plan for Achieving and Maintaining the National Ambient Air Quality Standards," Revision #4, State General Plan, South Coast Air Basin Plan, California Air Resources Board, December 31, 1973.

C-23. "Emissions and Air Quality Assessment," California Air Resources Board, Report No. ARB-EP-76001, April 1976.

C-24. Air/Water Pollution Report, 11(29), July 16, 1973, pp. 283-284.

APPENDIX D

DISPERSION MODELS FOR HEALTH EFFECTS

Two simple relationships are derived for order-of-magnitude estimates of ambient pollutant concentrations. These relations define dilution factors for point and area sources as the ratio of maximum ground level concentration to emission rate.

In the following sections the approach for arriving at these relationships is outlined and specific examples are given for the Chicago AQCR.

D.1 POINT SOURCES

A relation of the form $X_{max} = e/k$ is derived where X_{max} is the maximum ground concentration in $\mu g/m^3$ and e is the emission rate in Gg/yr. Figure D-1, which is a reproduction of Figure 3-9 of Turner's workbook (Reference D-1), is used to estimate the value of k. This figure gives $(Xu/e)_{max}$ as a function of the distance to the point of maximum concentration downwind of a point source. Three parameters are needed: average wind speed, u(m/sec), average emission height, H (m),* and the atmospheric stability class. Table D-1 shows a sample calculation for the Chicago AQCR with annual average wind speed of u = 4.5 m/s (Reference D-2) for three stack heights (Reference D-3) and three atmospheric stability classes. The stability classes are: most unstable (class A), average (class C) and most stable (class F). It is noted that parameter k does not vary significantly between A and C stability classes, but it is appreciably larger for F stability class. According to Turner (Table 3-1, Reference D-1), however, the average wind speed of 4.5 m/s corresponds to stability class C. Therefore, in the present calculations the value of k corresponding to this stability class is used. Based on this value of k, the maximum pollutant concentration in $\mu g/m^3$ for the average stack height of 87 m can be obtained from

$$x_{max} = 134\ e \qquad \text{(D-1)}$$

where e is the emission rate in Gg/yr.

---

*In the present calculations emission height is assumed to be equal to the stack height.

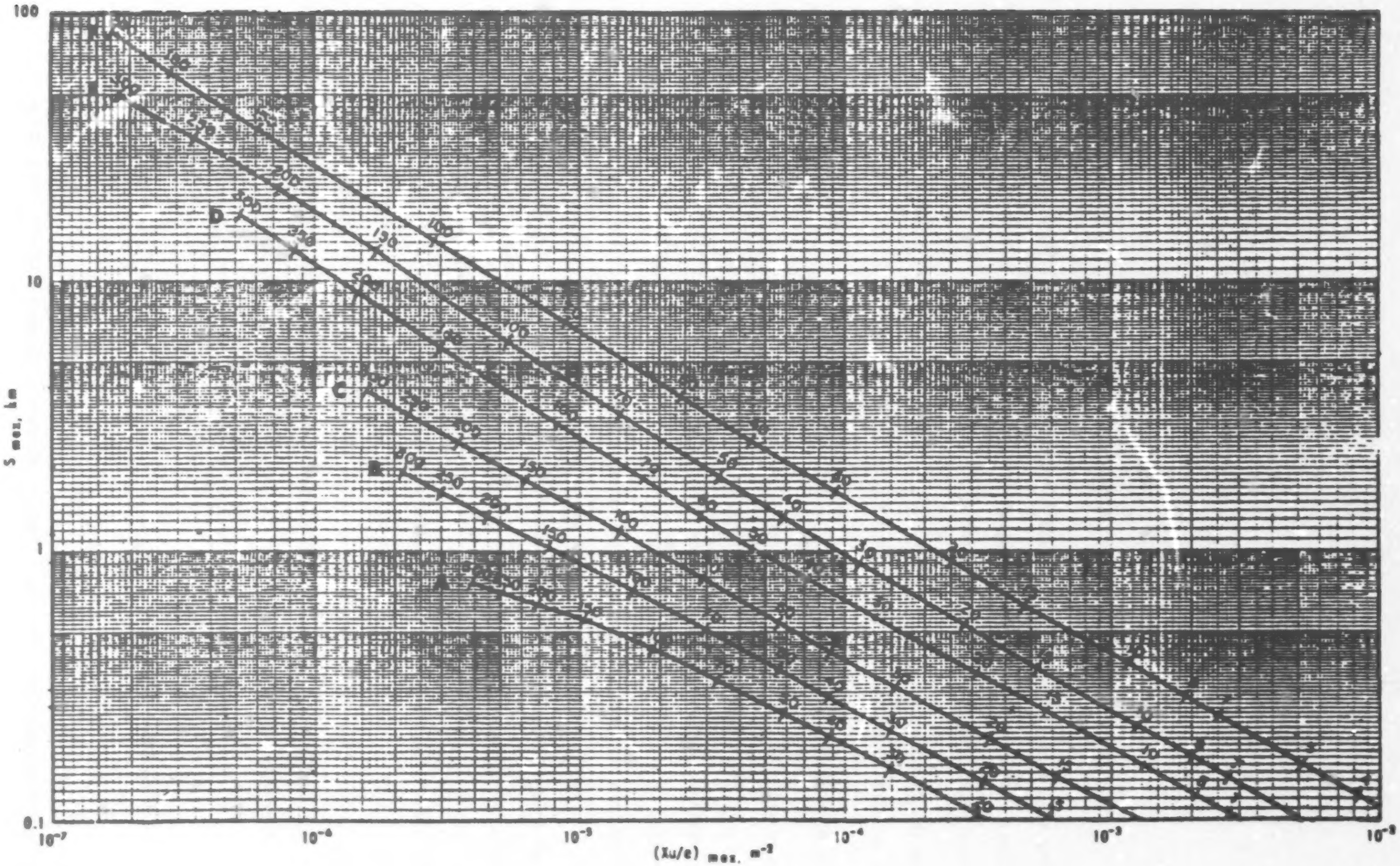


Figure D-1. Distance from source of maximum concentration and maximum Xu/e as a function of stability class and effective height (meters) of emission.

TABLE D-1. SAMPLE CALCULATIONS OF (Xu/e) MAX FOR POINT SOURCES IN THE CHICAGO AQCR

Wind Speed (m/s)	Emission Height (m)	$(X\ u/e)_{max} \times 10^5$ (m^{-2})			$k \times 10^{-6}$ (m^3/s)		
		Stability Class			Stability Class		
		A	C	F	A	C	F
4.5	56 (min)	5.0	4.5	1.8	0.07	0.1	0.25
4.5	87 (avg)	2.1	1.9	0.37	0.21	0.24	1.2
4.5	123 (max)	1.0	0.9	0.10	0.45	0.50	4.3

It should be noted that Equation (D-1) is obtained assuming that wind blows only in one direction. This equation can be modified according to frequency of the wind direction. For instance, based on 10-year weather data for Chicago (Reference D-4), maximum wind direction frequency is 12 percent, i.e., wind blows in a given direction 12 percent of the time, at the most. Thus, Equation (D-1) is modified correspondingly.

$$X_{max} = 16\ e \tag{D-2}$$

The accuracy of this equation is assessed in comparison with predictions made by Radian (Reference D-4) of maximum NO_x concentrations from several point sources in Chicago. Radian estimated maximum NO_x concentrations using the Climatological Dispersion Model (CDM) to predict X_{NO_x}. The predicted ratio of X_{NO_x}/e varies between 2.23 and 182.0 with the mean value of 32.4 which is in reasonable agreement with Equation (D-2).

To utilize Equation (D-2) for assessment of health and ecological impacts of pollutants it is desirable to further modify this equation in the following form:

$$X_{max} = C\ E\ \frac{1}{HV}\ (1.15\ AF + 1)\ e \tag{D-3}$$

Equation (D-3) relates the maximum ambient concentration, X_{max} in ppm to the emission e in ppm of the flue gas. E is the source thermal capacity in MW, HV is the heating value of the fuel in MJ/kg and AF is the stoichiometric air-fuel ratio (kg air/kg fuel).* The constant C is a function of stack height given by the following table.†

Stack height (m)	Source	$C \times 10^7$ (Equation (D-3))
87	utility	3.95
56	industrial	9.53

Equation (D-3) can be simplified by the observation that the quantity (1.15 AF + 1)/HV is approximately equal to 0.413 (kg fuel/MJ) for all three fuel categories of oil, gas, and coal. Assuming that $E_{utility} = 500$ MW and $E_{industrial} = 25$ MW, we can write:

$$X_{max}\ (\text{ppb}) = 0.082\ e\ (\text{ppm})\ \text{for utility sources} \tag{D-4}$$

---

*15 percent excess air combustion is assumed here.

†Molecular weight of the exhaust gas is taken to be 30.

and $$X_{max} \text{ (ppb)} = 0.0098 \, e \text{ (ppm) for industrial sources} \qquad \text{(D-5)}$$

where the units are shown in the parentheses.

D.2 AREA SOURCES

Several approaches can be taken to arrive at a simple equation relating ambient concentrations to the total emission rate of distributed sources in a given area. Due to nonuniformity of emissions in a given area, it is more appropriate to use an area average rather than the maximum concentration.

Holzworth (Reference D-5) has considered an area with along-wind length of S (meters) and has related the average ground level concentration $\overline{X}$ (g/m³) to average area emission rate $\overline{e}$ ($gm^{-2}s^{-1}$). He assumes a Gaussian cross-wind and vertical distributions of pollutants and considers the case where either S is small compared to cross-wind dimensions of the area or there is no cross-wind variation of X. Holzworth derives the following expressions for $\overline{X}/\overline{e}$:

$$\overline{X}/\overline{e} = 3.994 \quad (S/u)^{0.115} \qquad \text{for } \frac{S}{u} \leq t_H \qquad \text{(D-6)}$$

$$X/e = 3.613 \, H_m^{\;0.13} + \frac{S}{2H_m u} \qquad \text{for } \frac{S}{u} \geq t_H \qquad \text{(D-7)}$$

where $t_H = 0.471 \, H_m^{\;1.13}$ and H_m is the mixing height in meters. The assumption here is that vertical diffusion from each elemental source follows the Gaussian distribution for a defined travel time, t_H after which the vertical distribution of pollutants is assumed uniform.

An alternate approach is the box model where the pollutants are assumed to be uniformly dispersed in the volume formed by the area under consideration and the mixing height. Thus, the change in the concentration over a distance ΔS along the wind direction is

$$\Delta X = \frac{\overline{e} \, \Delta t}{H_m}$$

Assuming a constant wind speed $u = \frac{\Delta S}{\Delta t}$, and that x = 0 at t = 0:

$$X = \int_0^S \frac{\overline{e} \, dS}{H_m u} = \frac{\overline{e} \, S}{H_m u}$$

The average concentration over the distance S = ut will then be:

$$\overline{X} = \frac{1}{t}\int_0^t X dt = \frac{\overline{e}\,t}{2H_m}$$

or $$\overline{X}/\overline{e} = \frac{S}{2H_m u} \qquad \text{(D-8)}$$

It is noted that the above expression is the same as the second term in Equation (D-7). In fact for large values of S or small values of H_m and u, the difference between $\overline{X}/\overline{e}$ values from Equations (D-7) and (D-8) becomes small.

As was done for point sources, Equations (D-6) and (D-7) are further modified to arrive at dilution factors relating $\overline{X}$ in ppm to $\overline{e}$ in ppm of the exhaust gases for different categories of area sources. Again the Chicago AQCR is considered where, according to Reference D-5, the average (morning and afternoon) mixing height is H_m = 825 m, u = 4.5 m/s and s = 153 km (longest N-S distance). Therefore, from Equation (D-8)

$$X \text{ (ppm)} = 6.98 \times 10^{-13} \frac{FU \cdot HV}{A} \overline{e} \text{ (ppm)}$$

where FU is the total area fuel usage in kg/yr, HV is the fuel heating value in MJ/kg, and A is the total area in m^2.

Using NEDS 1973 data for annual fuel usage in the Chicago AQCR (oil, coal and gas) and the fact that A = 1.57 x 10^{10} m^2, the above equation becomes:

$$\overline{X}\text{(ppb)} = c\overline{e}\text{(ppm)} \qquad \text{(D-9)}$$

where c is given by the following table for residential, industrial and commercial sources:

Source	Fuel	c (Equation (D-9))
Residential	Oil, gas	0.017
Residential	Coal	0.001
Industrial	Coal, oil, gas	0.010
Commercial	Coal, oil, gas	0.008

Equations (D-4) and (D-5) for point sources and Equation (D-9) for area sources are used in Sections 3 and 7 to relate source emission to ambient pollutant concentrations. The dilution factors in these relations are derived for the specific example of the Chicago AQCR. It is, however, believed that they are of sufficient validity in the other AQCRs for the coarse screening done here.

REFERENCES FOR APPENDIX D

D-1. Turner, D.B., "Workbook of Atmospheric Dispersion Estimates," NAPCA, 1969.

D-2. Climatological Data — National Summary 1975 Annual Summary Vol. 26, No. 13, NOAA, Environmental Data Service.

D-3. "Steam-Electric Plant Air and Water Quality Control Data for the Year Ended 1972," Rept. #FPC-S-246 Federal Power Commission, Washington, D.C., March 1975.

D-4. Personal Communication with B.R. Eppright, Radian Corp., September 29, 1976.

D-5. Holzworth, G.C., "Mixing Heights, Wind Speeds, and Potential for Urban Air Pollution throughout the Contiguous United States," EPA OAP Publication #AP-101, January 1972.